

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Remedying Undue Discrimination
through Open Access Transmission Service
and Standard Electricity Market Design

Docket No. RM01-12-000

NOTICE OF PROPOSED RULEMAKING

(July 31, 2002)

I. INTRODUCTION

1. This notice of proposed rulemaking represents the third in a series of initiatives undertaken by the Commission to harness the benefits of competitive markets for the nation's electric energy customers, in order to meet our statutory responsibility to assure adequate and reliable supplies of electric energy at a just and reasonable price. In 1996, the Commission issued Order No. 888, which required, as a remedy for undue discrimination, that all public utilities provide open access transmission.¹ In 1999, the Commission issued Order No. 2000.² The Commission's objective was "for all

¹Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities and Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Order No. 888, 61 Fed. Reg. 21,540 (May 10, 1996), FERC Stats. & Regs. ¶ 31,036 (1996), order on reh'g, Order No. 888-A, 62 Fed. Reg. 12,274 (March 14, 1997), FERC Stats. & Regs. ¶ 31,048 (1997), order on reh'g, Order No. 888-B, 81 FERC ¶ 61,248 (1997), order on reh'g, Order No. 888-C, 82 FERC ¶ 61,046 (1998), aff'd in relevant part, remanded in part on other grounds sub nom. Transmission Access Policy Study Group, et al. v. FERC, 225 F.3d 667 (D.C. Cir. 2000), aff'd sub nom. New York v. FERC, 122 S. Ct. 1012 (2002).

²Regional Transmission Organizations, Order No. 2000, 65 Fed. Reg. 809 (January 6, 2000), FERC Stats. & Regs. ¶ 31,089 (1999), order on reh'g, Order No. 2000-A, 65
(continued...)

transmission owning entities in the Nation, including non-public utility entities, to place their transmission facilities under the control of appropriate regional transmission institutions [RTOs] in a timely manner."³

2. Order No. 888 and Order No. 2000 set the foundation upon which to build regional transmission institutions and competitive electricity markets. However, as events have transpired, there remain significant impediments to competitive markets and to the infrastructure needed to meet our electric energy demand. Unduly discriminatory transmission practices have continued to occur and inconsistent design and administration of short-term energy markets has resulted in pricing inefficiencies that can cause rates to be unjust and unreasonable. At the same time, the nature of the electric industry has changed in a way that makes the development of competitive wholesale markets all the more critical. The electric industry has evolved from one characterized by large, vertically integrated utilities to an industry with increasing wholesale trade and increasing numbers of independent buyers and sellers of wholesale power seeking non-discriminatory access to transmission facilities. Public utilities today purchase significantly more wholesale power to meet their load than in the past. Indeed, from 1989

²(...continued)

Fed. Reg. 12,088 (February 25, 2000), FERC Stats. & Regs. ¶ 31,092 (2000), petitions for review dismissed, Public Utility District No. 1 of Snohomish County, Washington v. FERC, 272 F.3d 607 (D.C. Cir. 2001).

³Regional Transmission Organizations, 64 Fed. Reg. 31,389 (May 13, 1999), FERC Stats. & Regs. ¶ 32,541 at 33,685 (1999) (Notice of Proposed Rulemaking).

through 2000, their wholesale purchases increased from 18 percent of their total available electric energy to over 37 percent, and this percentage is expected to continue to grow.⁴

3. The Commission's objectives in this third rulemaking initiative, therefore, are to remedy remaining undue discrimination and establish a standardized transmission service and wholesale electric market design that will provide a level playing field for all entities that seek to participate in wholesale electric markets. The Commission proposes to provide new choices through a flexible transmission service, and an open and transparent spot market⁵ design that provides the right pricing signals for investment in transmission and generation facilities, as well as investment in demand reduction.

4. When supply and demand do not support fully competitive markets, market design should provide protection against market power. We seek in this rulemaking to put in place sufficient regulatory backstops to protect customers against the exercise of market power when structures do not support a competitive market. Market monitoring at all times, and market power mitigation when needed, are critical pieces of this initiative.

⁴See Section III.C. for a more detailed discussion.

⁵The term "spot market" typically refers to a trade that covers a short period in the very near future. Trading in an independent transmission system operator (ISO) real-time or day-ahead market is referred to here as occurring in the spot market. In the Western price mitigation order, the Commission defined a spot market trade as any trade lasting 24 hours or less, whether a bilateral trade or a trade occurring in an organized real-time or day-ahead market that does not match up particular sellers and buyers. See San Diego Gas and Electric Company v. Sellers of Energy and Ancillary Services into Markets Operated by the California Independent System Operator and the California Power Exchange, 95 FERC ¶ 61,418 at 64,525 n.3 (2001). We will adopt this meaning for this rulemaking.

5. A significant impediment to achieving the full benefits of competition is that there is no single set of rules governing transmission of electric energy. Not only does the Order No. 888 pro forma tariff contain provisions that allow different types of customers to be treated differently, but there also are conflicting state and Federal rules governing the use of interstate transmission facilities. This provides opportunities for transmission providers to establish and apply rules in a way that unduly discriminates against certain classes of customers, leads to significant transaction costs and threatens reliability.

6. To remedy undue discrimination, enhance competition, remove economic inefficiencies and ensure just and reasonable rates, terms and conditions transmission of electric energy, the Commission proposes to: exercise jurisdiction over the transmission component of bundled retail transactions; modify the existing pro forma transmission tariff to include a single flexible transmission service (Network Access Service) that applies consistent transmission rules for all transmission customers – wholesale, unbundled retail and bundled retail; and provide a standard market design for wholesale electric markets. While it is critical that the same non-rate terms and conditions be applied to all transmission uses, including bundled retail, as soon as possible, we intend to work closely with our state colleagues with respect to transition issues involving bundled retail transmission rates.

7. The proposed Network Access Service would combine features of both existing open access transmission services – the flexibility and resource and load integration of Network Integration Transmission Service; and the reassignment rights of Point-to-Point

Transmission Service. It would give a customer the right to transmit power between any points on the transmission system – so long as the transaction is feasible under a security-constrained dispatch.

8. We expect that most if not all entities will become members of RTOs and that the new Network Access Service would be provided through these RTOs. However, this rule may become effective at a time when some transmission owners and operators have not yet become members of functioning RTOs. Thus, we propose that all transmission owners and operators that have not yet joined an RTO must contract with an independent entity to operate their transmission facilities. This proposed rule refers to both the RTO and those independent entities as "Independent Transmission Providers." An Independent Transmission Provider would have no financial interest, either directly or through an affiliate, as defined in section 2(a)(11) of the Public Utility Holding Company Act (15 U.S.C. § 79b(a)(11)), in any market participant⁶ in the region in which it provides transmission services or in neighboring regions. We propose that all Independent

⁶A market participant means:

- (i) Any entity that, either directly or through an affiliate, sells or brokers electric energy, or provides ancillary services to the [RTO], unless the Commission finds that the entity does not have economic or commercial interests that would be significantly affected by the [RTO's] actions or decisions; and (ii) Any entity that the Commission finds has economic or commercial interests that would be significantly affected by the [RTO's] actions or decisions.

Transmission Providers administer the day-ahead and real-time markets. As discussed infra, we also have identified long-term planning and expansion, system impact and facilities studies and transmission transfer capability calculations (including postings on an Open Access Same-time Information System (OASIS)) as tasks that must be done on a regional basis. Thus, we propose that all Independent Transmission Providers perform these tasks.

9. In addition to creating the new Network Access Service, the revised tariff would include requirements to standardize wholesale electric market design. The fundamental goal of the Standard Market Design requirements, in conjunction with the standardized transmission service, is to create "seamless" wholesale power markets that allow sellers to transact easily across transmission grid boundaries and that allow customers to receive the benefits of lower-cost and more reliable electric supply. For example, currently a supplier that seeks to serve load in a distant state may need to cross several utility systems or independent system operator systems (ISOs), all of which have different rules for such things as reserving and scheduling transmission and scheduling generation. This can either result in an efficient transaction not occurring at all or it can add significant time and costs to the transaction. Standard Market Design seeks to eliminate such impediments.

10. Central to the Standard Market Design concept is its reliance on bilateral contracts entered into between buyers and sellers. The resource adequacy requirement strongly encourages such long-term contracts. The short-term spot markets set out below are

intended to complement bilateral procurement. To handle generation imbalances and the procurement of ancillary services, the Commission proposes to require that all Independent Transmission Providers operate markets for energy and for the procurement of certain ancillary services in conjunction with markets for transmission service. These markets would be bid-based, security-constrained spot markets operated in two time frames: (1) a day ahead of real-time operations, and (2) in real time. The adoption of a market-based locational marginal pricing (LMP) transmission congestion management system is designed to provide a mechanism for allocating scarce transmission capacity to those who value it most, while also sending proper price signals to encourage short-term efficiency in the provision of transmission service as well as wholesale energy, and to encourage long-term efficiency in the development of transmission, generation and demand response infrastructure. We expect that market participants will strike an appropriate balance between bilateral contracts and spot market transactions. Efficient spot markets with appropriate price signals bring bilateral and spot market prices closer together, helping to assure customers of efficient bilateral markets.

11. Several changes required by Standard Market Design promote greater customer access to low-cost power. We note that this may raise concerns that cheap power may leave one region for sale in another, higher-priced region. This can only happen with generation that is not already under contract for purchase. Thus, customers in low-cost regions can ensure that low-cost power "stays home" by contracting for that power. This way, only excess power will leave the region to serve another market.

12. The Commission proposes a pricing policy and process for recovering the costs of new transmission investment so as to develop the infrastructure needed to support competitive markets. The policy builds on the price signals provided by the proposed spot market design. However, there are cases where LMP price signals alone will not encourage all beneficial transmission investments. Therefore, we propose to require market participants to participate in a regional process to identify the most efficient and effective means to maintain reliability and eliminate critical transmission constraints.

13. Even with good market design rules, current supply and demand conditions make a market monitoring and market power mitigation plan necessary. The market power mitigation proposed in this rule would rely on a combination of methods to protect against the exercise of market power by preventing sellers from withholding economical supplies from the market, while permitting prices to reflect true scarcity. The proposed market power mitigation method should be more restrictive at times or places where the exercise of market power is more likely to occur than at times or places where the market is sufficiently competitive.

14. However, because market power mitigation may tend to suppress scarcity prices that signal the need for investment, a companion mechanism besides spot prices is needed. The Commission proposes a resource adequacy requirement to ensure adequate electric generating, transmission and demand response infrastructure, the level of which is to be determined on a regional basis. Recognizing that supply planning and retail customer demand response are the states' responsibility, the Commission proposes a

resource adequacy requirement intended to complement existing state programs. In particular, the Commission proposes that an RTO or other regional entity must forecast the region's future resource needs, facilitate regional determination of an adequate future level of resources and assess the adequacy of the plans of load-serving entities⁷ to meet the regional needs. Each load-serving entity would be required to meet its share of the future regional need through a combination of generation and demand reduction.

15. In summary, in this proceeding, the Commission, pursuant to its authority under sections 205 and 206 of the Federal Power Act,⁸ proposes to:

- (1) establish a single non-discriminatory open access transmission tariff with a single transmission service (Network Access Service) that is applicable to all users of the interstate transmission grid: wholesale and unbundled retail transmission customers, and bundled retail customers;
- (2) require all public utilities that own, control or operate interstate transmission facilities to become an Independent Transmission Provider, turn over their transmission facilities to an Independent Transmission Provider or contract with an Independent Transmission Provider to operate

⁷A load-serving entity is an entity, including a municipal electric system and an electric cooperative, authorized by law, regulatory authorization or requirement, agreement, or contractual obligation to supply energy, capacity, and/or ancillary services to retail customers located within the transmission provider's service area, including an entity that takes service directly from the transmission provider to supply its own load in the transmission provider's service area. See SMD Tariff § 1.

⁸16 U.S.C. 824d and 824e (1994).

their facilities. An Independent Transmission Provider is any public utility that owns, controls or operates facilities used for the transmission of electric energy in interstate commerce, that administers the day-ahead and real-time energy and ancillary services markets in connection with its provision of transmission services pursuant to the SMD Tariff, and that is independent (i.e., has no financial interest, either directly or through an affiliate, as defined in section 2(a)(11) of the Public Utility Holding Company Act (15 U.S.C. § 79b(a)(11), in any market participant in the region in which it provides transmission service or in neighboring regions).

- (3) require that an Independent Transmission Provider provide transmission services and administer the day-ahead and real-time energy and ancillary services markets;
- (4) establish an access charge to recover embedded transmission costs based on a customer's load ratio share of the Independent Transmission Provider's costs, and would be paid by any customer taking power off the grid;⁹

⁹As explained in Section IV.D.1, current long-term point-to-point customers that seek to receive Congestion Revenue Rights would also pay the access charge.

- (5) use LMP as the system for transmission congestion management and provide tradable financial rights – Congestion Revenue Rights¹⁰ – as a means to lock in a fixed price for transmission service;
- (6) establish a preference for the auction of Congestion Revenue Rights, but initially allow regional flexibility for a four-year transition period in determining whether to allocate Congestion Revenue Rights to existing customers or auction such rights such that revenues are allocated to existing customers to hold them financially harmless;
- (7) establish open imbalance energy markets to allow all market participants to buy or sell their imbalances in a fair, efficient and non-discriminatory market. Imbalance markets would be neutral towards fuel sources and treat demand resources on an equal footing with supply;
- (8) permit customers under existing contracts to receive the same level and quality of service under Standard Market Design that they receive under their current contracts, to the greatest extent feasible;
- (9) establish procedures to mitigate market power in the day-ahead and real-time markets required by Standard Market Design and mechanisms for market monitoring;

¹⁰These rights were called "Transmission Rights" in the Working Paper on Standardized Transmission Service and Wholesale Electric Market Design, Docket No. RM01-12-000 (Mar. 15, 2002) (hereinafter Working Paper).

- (10) establish procedures to assure, on a long-term regional basis, that there are adequate transmission, generation and demand-side resources;
- (11) provide a formal role for state representatives to participate in the decision-making processes of Independent Transmission Providers; and
- (12) clarify the obligation of all users of the transmission system to comply with all appropriate standards for ensuring system security and reliability.

16. The Commission's focus is on promoting the development of competitive wholesale markets and we do not intend to interfere with the legitimate concerns of state regulatory authorities. It remains within a state's authority to determine whether or not to provide retail access. Nevertheless, the reforms proposed in this rulemaking will benefit customers in states with or without retail access. In addition, we seek to formally involve state representatives in the decision-making processes of regional entities. We also recognize the need to permit parties to continue to rely on existing contracts and scheduling practices, including those involving hydroelectric power, and these are fully accommodated under Standard Market Design.

17. The Commission recognizes that differences exist throughout the regions of the country; however, the Commission's goal is to remedy undue discrimination by standardizing transmission service and wholesale electric market design as much as possible. We propose to allow certain regional variations, as described infra.

18. Finally, the Commission recognizes that implementation of a revised open access transmission tariff and Standard Market Design on a nationwide basis may take some

time. Thus, the Commission proposes a phased compliance process. By July 31, 2003, all public utilities that own, operate or control interstate transmission facilities must file revised open access transmission tariffs (Interim Tariffs) to become effective September 30, 2004, that reflect the inclusion of bundled retail customers as eligible customers. By December 1, 2003, all public utilities that own, control or operate interstate transmission facilities must file revised open access transmission tariffs (SMD Tariffs), to become effective no later than September 30, 2004, or such other time as directed by the Commission, that reflect all of the remaining revisions and requirements of the Final Rule in this proceeding. The Commission and its staff will work with regional organizations and stakeholders in facilitating full and efficient compliance with this rule.

19. Below in Section II we set out the relevant developments in the electric industry. In Section III and Appendix C we explain the need for further reform. In Appendix E, we discuss various allegations of market manipulation strategies encountered in the organized markets and how Standard Market Design will address these strategies. In Section IV we explain our specific remedy for pervasive problems in the industry consistent with our statutory responsibilities. In Section V, we set out the implementation process and dates. Finally, the glossary for the terms used in this document is found in the Definitions section of the SMD Tariff in Appendix B, and the revisions to the Interim Tariff are set out in Appendix A.

II. Background: Order No. 888 and Order No. 2000

A. Order Nos. 888 and 888-A

20. In April 1996, in Order No. 888, the Commission found that unduly discriminatory and anticompetitive practices existed in the electric industry, and that public utilities that own, control or operate interstate transmission facilities had discriminated against others seeking transmission access. It determined that non-discriminatory open access transmission services, including access to transmission information, and stranded cost recovery were the most critical components of a successful transition to competitive wholesale electricity markets.¹¹ The Commission stated that its goal was to ensure that customers have the benefits of competitively priced generation.

21. Order No. 888 required all public utilities that own, control or operate facilities used for transmitting electric energy in interstate commerce to: (1) file open access non-discriminatory transmission tariffs containing certain minimum, non-price terms and conditions, and (2) functionally unbundle wholesale power services from transmission services.¹² Functional unbundling requires public utilities to: (1) take wholesale transmission services under the same tariff of general applicability as they offer their customers; (2) state separate rates for wholesale generation, transmission, and ancillary services; and (3) rely on the same electronic information network that their transmission customers rely on to obtain information about the utilities' transmission systems.¹³ In Order No. 889, issued concurrent with Order No. 888, the Commission also imposed

¹¹See Order No. 888 at 31,652.

¹²See *id.* at 31,635-36.

¹³See *id.* at 31,654.

standards of conduct governing communications between the utility's transmission and wholesale power functions, to prevent the utility from giving its power marketing arm preferential access to transmission information.¹⁴ Under Order No. 889, all public utilities that own, control or operate facilities used in the transmission of electric energy in interstate commerce are required to create or participate in an OASIS that provides existing and potential transmission customers the same access to transmission information that will enable them to obtain open access non-discriminatory transmission service.

22. The Commission declined to require corporate unbundling at the time of Order No. 888, and stated instead that efforts to remedy undue discrimination should begin by requiring the less intrusive functional unbundling approach.¹⁵ While the Commission in Order No. 888 encouraged the creation of ISOs and set forth eleven principles for assessing ISO proposals submitted to the Commission, it did not mandate regional organizations.¹⁶ The Commission in Order No. 888 stated:

[W]e see many benefits in ISOs, and encourage utilities to consider ISOs as a tool to meet the demands of the competitive marketplace. As a further precaution against discriminatory behavior, we will continue to monitor electricity markets to ensure that functional unbundling adequately protects transmission customers. At the same time, we will analyze all alternative proposals, including formation

¹⁴See Open Access Same-Time Information System and Standards of Conduct, Order No. 889, 61 Fed. Reg. 21,737 (April 24 1996), FERC Stats. & Regs. ¶ 31,035 at 31,588-91 (1996), order on reh'g, Order No. 889-A, 62 Fed. Reg. 12,484 (March 4, 1997), FERC Stats. & Regs. ¶ 31,049 (1997).

¹⁵See Order No. 888 at 31,654.

¹⁶See id. at 31,730-32.

of ISOs, and, if it becomes apparent that functional unbundling is inadequate or unworkable in assuring non-discriminatory open access transmission, we will reevaluate our position and decide whether other mechanisms, such as ISOs, should be required. ^[17]

Order No. 888-A reaffirmed the findings of Order No. 888. The Court of Appeals for the District of Columbia Circuit upheld the orders "in nearly all respects."¹⁸ The Supreme Court recently affirmed.¹⁹

23. A number of significant developments took place in the electric utility industry following issuance of Order No. 888. All public utilities filed non-discriminatory, open access transmission tariffs stating rates, terms and conditions for comparable wholesale transmission service to third-party users of their transmission systems. With the advent of OASIS systems, improved information about transmission systems became available to all participants in the bulk power market at the same time that it was available to utilities' own wholesale merchant functions and wholesale marketing affiliates (although further information improvements are still needed). New generation resources were developed in areas that had experienced generation shortages.²⁰ Regional trading patterns have expanded. In addition, the Commission granted a large number of merger applications

¹⁷Id. at 31,655.

¹⁸Transmission Access Policy Study Group, 225 F.3d at 681.

¹⁹See New York v. FERC, 122 S.Ct. 1012.

²⁰See Staff Report to the Federal Energy Regulatory Commission on the Causes of the Pricing Abnormalities in the Midwest During June 1998 (1998), available in <<http://www.ferc.gov/electric/mastback.pdf>>.

and applications to charge market-based rates, effecting structural changes in the industry. The industry thus became less localized and more regionalized, with a growing need for regional planning and regulation. And as part of that regionalization, the Commission also approved voluntary ISOs in five regions of the country – New England, New York, PJM,²¹ the Midwest and California (an ISO was also formed in ERCOT, but it is not under the Commission's full jurisdiction). These ISOs are the precursors to regional entities identified as RTOs, in the Commission's Order No. 2000, discussed below.

B. Order No. 2000

24. Order No. 2000, issued in December 1999, was the Commission's second major step toward establishing competitive wholesale power markets and eliminating residual undue discrimination in interstate transmission services. It identified two broad categories of impediments to competitive electricity markets: (1) the engineering and economic inefficiencies inherent in the current operation and expansion of the transmission grid, and (2) continuing opportunities for transmission owners to unduly discriminate in the operation of their transmission systems so as to favor their own (or their affiliates') power marketing activities.²² Further, evidence indicated that local

²¹The PJM ISO takes its name from the former Pennsylvania, New Jersey, Maryland Power Pool, which serves New Jersey, Maryland, Delaware, much of eastern Pennsylvania, the District of Columbia, and a small area of Virginia.

²²Order No. 2000 identified four specific areas of concerns: (1) calculation and posting of Available Transfer Capability in a manner favorable to the transmission provider; (2) standards of conduct violations; (3) line loading relief and congestion
(continued...)

management of the transmission grid by many individual vertically integrated utilities was inadequate to support the efficient, reliable regionwide operation that was needed for continued development of competitive markets. The Commission concluded that establishing independent RTOs would eliminate residual undue discrimination in transmission, enhance the benefits of competitive electricity markets, and could: (1) improve efficiency in transmission grid management; (2) improve grid reliability; (3) remove remaining opportunities for discriminatory transmission practices; (4) improve market performance; and (5) facilitate lighter-handed regulation. The Commission anticipated that formation of regional transmission grids would result in a substantial cost savings to the electric utility industry and its customers.²³

25. Order No. 2000 encouraged all transmission owners to voluntarily place their transmission facilities in the hands of appropriate RTOs. The Commission stated that RTOs could include ISOs or independent for-profit transmission companies (ITCs). However, all RTOs must meet four minimum characteristics and eight minimum functions that were identified in Order No. 2000, and also must have an open architecture

²²(...continued)
management; and (4) OASIS sites that are difficult to use. See Order No. 2000 at 31,005 n.69. The order also identified parallel path flows, planning and investing in new transmission facilities, pancaking of access charges, the absence of secondary markets in transmission service and the possible disincentives created by the level and structure of transmission rates. See id. at 31,014.

²³See id. at 30,993.

framework that would permit an RTO and its members flexibility to improve their structures over time.²⁴

26. Following Order No. 2000, some transmission-owning public utilities began to file proposals to participate in RTOs. The process has been slow for several reasons, one of which is stakeholder uncertainty about what the Commission would require for RTO approval – not only for the RTO scope and independence characteristics, but also regarding such RTO functions as congestion management and market-oriented provision of ancillary services.

27. Order No. 2000 called for RTOs to be in operation across the nation by December 2001. To date, there is only one RTO fully approved by the Commission, the Midwest ISO, which began operating in early 2002.²⁵ The Midwest ISO is large. It stretches from an eastern boundary in western Pennsylvania westward to the Rocky Mountains, northward into Manitoba, Canada and southward to the Texas border.

28. Although progress with Commission-approved RTOs has been slow, regionalization has also occurred through the ISO formation process that was encouraged in Order No. 888. The Northeast and California ISOs are engaged in a process to become

²⁴The four RTO characteristics are: (1) independence; (2) scope and regional configuration; (3) operational authority; and (4) short-term reliability. The eight RTO functions are: (1) tariff administration and design; (2) congestion management; (3) parallel path flow; (4) ancillary services; (5) OASIS, Total Transfer Capability and Available Transfer Capability; (6) market monitoring; (7) planning and expansion; and (8) interregional coordination. See Order No. 2000 at 30,993-94.

²⁵See Midwest Independent System Operator, Inc., 97 FERC ¶ 61,326 (2001).

Commission-approved RTOs or to join larger RTOs. In eastern North America, close coordination is developing between U.S. and Canadian transmission systems and market designs.

29. In addition to the Midwest ISO, the Commission has provisionally approved other RTOs,²⁶ and authorized operation of ITCs that operate under an RTO umbrella.²⁷ The Commission also ordered Northeastern and Southeastern RTO applicants, including some applicants whose RTO proposals had been provisionally approved, into mediation proceedings to facilitate the formation of RTOs in those areas.²⁸ The Commission further noted that a "west wide RTO, or a seamless integration of Western RTOs, is the best vehicle for designing and implementing a long-term regional solution" to the West's electric generation supply crisis.²⁹

²⁶See GridSouth Transco, LLC, 94 FERC ¶ 61,273 (2001); GridFlorida, LLC, 94 FERC ¶ 61,363 (2001); and PJM Interconnection, LLC, 96 FERC ¶ 61,061 (2001).

²⁷See TRANSLink Transmission Company, L.L.C., et al., 99 FERC ¶ 61,106 (2002) (authorizing operation of ITC within the Midwest ISO), reh'g pending, Docket Nos. EC01-156-001 et al.; Alliance Companies, et al., 99 FERC ¶ 61,105 (2002) (authorizing the operation of an ITC).

²⁸See Regional Transmission Organizations, 96 FERC ¶ 61,065 (2001) (initiating mediation proceedings between Northeastern RTO applicants); Regional Transmission Organizations, 96 FERC ¶ 61,066 (2001) (initiating mediation proceedings between Southeastern RTO applicants).

²⁹Removing Obstacles to Increased Electric Generation and Natural Gas Supply in the Western United States, 94 FERC ¶ 61,272 at 61,974 (2001). A coalition of Western utilities (RTO West Filing Utilities) filed a proposal on October 16, 2001 to create RTO West. The Commission granted several of the RTO West Filing Utilities' requests for declaratory order on April 26, 2001, finding some of RTO West's proposed characteristics (continued...)

30. The following section and related Appendix C discuss specific features of today's wholesale electricity markets that inhibit the development of competition and efficient regional markets, and identify areas in which the Commission must direct reforms to eliminate remaining undue discrimination and inefficiencies, and ensure just and reasonable rates.

III. NEED FOR REFORM

A. Undue Discrimination and Impediments to Competition Remain

31. Since the issuance of Order Nos. 888 and 2000, it has become clear that additional, mandatory measures are needed to achieve the goals of non-discriminatory transmission access and competition in electricity markets. Vertically integrated transmission owners and operators continue to use their interstate transmission facilities in ways that inhibit competition in wholesale power markets as well as competition in those retail power markets where states have adopted retail choice. The discriminatory preferences that these transmission owners and operators give to their own uses of the interstate transmission grid to serve their retail customers (whether or not they are in retail choice states) results in discrimination against, and in costs being borne by, other wholesale and

²⁹(...continued)

and functions compliant with Order No. 2000. See Avista Corporation, et al., 95 FERC ¶ 61,114 (2001). The RTO West Filing Utilities then filed a proposal for Stage 2 of RTO West's creation on March 28, 2002. The Stage 2 proposal is intended to enable the Commission to determine whether the RTO West proposal fulfills all of the Order No. 2000 characteristics and functions. See Stage 2 Filing and Request for Declaratory Order Pursuant to Order 2000 at 5, Docket No. RT01-35-000 (Mar. 28, 2002).

retail customers who also rely on the interstate transmission facilities to buy power. The discriminatory preferences also create barriers to new sellers that could provide lower-cost power. This could result in higher prices to the native load served by the transmission owner. For example, transmission-dependent utilities³⁰ and other load-serving entities need the interstate transmission facilities to move power they are purchasing by contract from distant generators or suppliers, but allege that despite the requirements of Order No. 888, they are denied comparable access to the grid. Similarly, new generators wishing to compete in wholesale markets or for retail customers in retail choice states tell us that they are denied comparable access to the grid, thus inhibiting entry of new, lower-cost, efficient and environmentally superior power suppliers.

32. The Commission recently has taken additional steps to address some of the remaining impediments to non-discriminatory transmission access and competition in wholesale power markets. For example, the Commission's recently issued Generator Interconnection proposed rule seeks to remove one particular type of undue discrimination occurring in the marketplace – barriers to obtaining interconnections to the interstate transmission grid – so that new generators can compete with vertically integrated transmission providers to serve load.³¹ However, this initiative will resolve

³⁰A transmission-dependent utility is a utility that does not own generation and relies on its neighboring utilities to transmit power to it that it purchases from its suppliers.

³¹See Standardization of Generator Interconnection Agreements and Procedures,
(continued...)

only one aspect of remaining discriminatory practices. Other opportunities for vertically integrated transmission providers to operate in ways that favor their own generation remain within the construct of the pro forma tariff (e.g., preferences for native load and network customers to reserve transmission capability, differing transmission services that raise barriers to competition, the lack of inclusion of all services under the same tariff). As noted in Order No. 2000, "perceptions of discrimination are significant impediments to competitive markets. Efficient and competitive markets will develop only if market participants have confidence that the system is administered fairly."³²

33. Furthermore, it has become apparent that there are also opportunities to discriminate and to hinder an efficient, competitive marketplace due to the absence of standardization with respect to market rules and practices within and between regional markets. So-called "seams" problems (e.g., different rules and different pricing systems) create transaction costs and artificial barriers to trade. These problems inhibit the

³¹(...continued)

67 Fed. Reg. 22,249 (May 2, 2002), FERC Stats. & Regs. ¶ 32,560 at 34,174 (2002) (Notice of Proposed Rulemaking). The proposed rule defines interconnection study time frames and grants all generators the opportunity to be treated as competing network resources in meeting load and load growth. See id. at 34,243-45.

³²Order No. 2000 at 31,017. Lack of market confidence may lead to a reluctance on the part of market participants to share operational real-time and planning data with transmission providers because of the suspicion that they could be providing a competitive advantage to their affiliated power marketers. It may also deter generation expansion and lead to the perception that the transmission provider's generation is more reliable, thereby reducing competition and raising prices for customers. See id.

Commission from fulfilling its statutory responsibility to ensure that customers receive reliable power supplies at the lowest reasonable costs.³³

34. Finally, innovation that the Commission expected to see with respect to new service offerings has been sporadic and unsteady. Innovations in transmission control and pricing (e.g., ISO control of transmission and LMP for generation and transmission services in the Northeast, RTO formation in the Midwest), while impressive, have been slow to take root in other regions of the country. The pro forma tariff was envisioned as the baseline above which transmission providers were encouraged to develop competitive and customer-responsive service offerings. But Florida Power Corporation's network contract demand service, a hybrid of Network Integration Transmission Service and Point-to-Point Transmission Service features,³⁴ and Duke Energy Corporation's "recallable long-term firm" service³⁵ are the only noteworthy new services accepted by the Commission for use with a single utility's open access transmission tariff. Other proposed pro forma tariff revisions amounted to little more than working around the edges of the existing services and procedures and did not produce more competitive transmission service that reduces overall electricity costs.

³³See FPC v. Hope Natural Gas Company, 320 U.S. 591, 610 (1944).

³⁴See Florida Power Corporation, 81 FERC ¶ 61,247 (1997).

³⁵See Duke Energy Corporation, 88 FERC ¶ 61,184, reh'g denied, 89 FERC ¶ 61,190 (1999).

35. Most ISOs recently introduced centralized short-term real-time hourly markets and day-ahead markets for energy (i.e., spot markets) where sellers sell into the market and buyers buy from the market without matching a particular seller with a particular buyer. In such organized spot markets, there is a single market clearing price established that is received by all generators who bid into the market below that price and is paid by all load that bids in above that price. However, the ability of customers to bid demand reductions into the spot market in response to supplier prices is still limited and needs to be improved significantly for short-term markets to operate more competitively. Further, while there have been benefits of market development in the Northeast (PJM, New York ISO, ISO-New England), Texas and California (during the first two years of its restructuring), the Midwest ISO is still in the formative stages of operation with respect to markets, and few market benefits have materialized in the Southeast and West.

B. Specific Instances of Undue Discrimination and Impediments to Competition

36. The specific reasons for requiring reform are many. Market participants have identified, through formal complaints, hotline calls, public conferences, and pleadings, the difficulties they have experienced in gaining equal access to the transmission grid to compete with vertically integrated utilities to serve load. Much of this problem is directly attributable to the remaining ability of such vertically integrated utilities (and the existence of sufficient incentives) to exercise some degree of transmission market power in order to protect their own generation market share. Further complicating transmission

access is the fact that not all transmission service is provided under the rates, terms and conditions of the Commission's pro forma tariff. Rather, over 60 percent of load has been subject to various state rules governing the transmission component of bundled retail transactions. Independent transmission service under a common set of rules would solve many of these problems.

37. Nevertheless, new problems have been created by some of the market design experiments. In regions of the country where the separation of transmission from generation has been addressed through the creation of ISOs (which, in some instances, have placed nearly all load under a single tariff), market design flaws create inefficiencies in the marketplace and opportunities for the exercise of market power. Conflicting market rules and procedures in neighboring ISOs have created or perpetuated seams problems that impede the economic flow of power from one region to another. All of these problems have hindered the progress towards competitive regional electricity markets. Standard Market Design is intended to address these problems.

1. Transmission Market Power by Utilities that are Not Independent

38. By differing means, Order Nos. 888 and 2000 attempt to effect open access transmission by reducing the ability of transmission owners that also own generators to act in anticompetitive or unduly discriminatory ways against other generators. In both orders, the Commission attempted to move the electric industry into a competitive wholesale market without mandating corporate restructuring. Through Order Nos. 888 and 2000, the Commission required open access to public utility transmission systems,

encouraged the formation of ISOs and, later, RTOs to achieve control of the transmission grid by entities that are independent from generation marketing or sales. However, only limited portions of the country have moved beyond the basic requirements of open access (e.g., through the voluntary divestiture of generation or establishment of RTOs, ISOs, or ITCs). In the rest of the country, the remaining corporate ties between generation and transmission within public utilities have proven problematic for transmission access. Thus, across most of the nation, barriers to entry remain for new generators and new load-serving entities.

39. A large portion of this problem is directly attributable to the continued ability of vertically integrated transmission providers to exercise some degree of transmission market power to advantage their own or affiliated generation. The longer the vertically integrated transmission provider can use access to interconnection or transmission service to delay or prevent entry of competing generators to its service territory, the longer it can profit from its own generation sales with a limited threat of competition. Vertically integrated transmission providers have found numerous ways to delay or prevent entry of competitors, some within the existing rules and some by exceeding reasonable discretion afforded to the transmission provider. All of these are difficult to monitor or prevent with behavioral rules.³⁶

³⁶See Working Paper at 21 (Mar. 15, 2002); see also Comment of the Staff of the Bureau of Economics and Office of General Counsel of the Federal Trade Commission, Docket No. RM01-12-000 (July 23, 2002).

40. As part of Standard Market Design, we propose that an Independent Transmission Provider operate all transmission facilities. The requirement for independent control of the transmission grid, preferably by an RTO, resolves these types of problems.

a. Load Growth

41. Under the current pro forma tariff, a transmission provider is required to plan its system to allow customers with existing long-term contracts to extend, or roll over, those contracts.³⁷ However, the transmission provider has a right to recall that transmission capacity if it identified in the initial agreement with the customer that it had projected native load growth that would require that transmission capacity.³⁸ Transmission providers have failed to identify any native load growth at the time of the initial agreement, and disputes have arisen with customers claiming they were denied the ability to roll over their contracts because the transmission provider claimed, well after the contract was executed, that the transmission capacity at issue was required to serve native load growth.³⁹

³⁷ See Section 2.2 of the current pro forma tariff.

³⁸ See Order No. 888-A at 30,277.

³⁹ See Public Service Company of New Mexico v. Arizona Public Service Co., 99 FERC ¶ 61,162 (2002), for a recent example. In this case, the Commission directed APS to grant PSNM's request to extend its contract for 60 MW of Point-to-Point Transmission Service. APS had attempted to deny the rollover request on the basis that it had verbally informed PSNM that capacity would not be available due to APS's future native load growth. The Commission restated the principle that a transmission provider can deny a customer the ability to roll over its long-term firm service contract only if the transmission provider includes in the service agreement a specific limitation based on

(continued...)

42. In Standard Market Design, we propose to eliminate the preference for future native load growth. Instead, since Congestion Revenue Rights will be used to assure price certainty, Congestion Revenue Rights will be apportioned based on historical use or by an auction, neither of which grants preference for future load growth by a particular supplier; this approach resolves these concerns.

b. Delays in Responding to Requests for Service

43. Another type of anticompetitive behavior centers on a vertically integrated transmission provider delaying the processing of a competitor's request for new transmission service or interconnection (including the related system impact or facilities studies). Transmission providers have done so by failing to follow time lines or expansively interpreting the tariff procedures. These delays may be enough to cause the competing generator to lose the sale, particularly if the potential customer is concerned that it may lose service completely if it does not stay with the transmission provider.⁴⁰

44. Under Standard Market Design, these types of delays are resolved through the requirement for an independent entity, preferably an RTO, to perform studies and

³⁹(...continued)

reasonably forecasted native load needs that will use the transmission capacity provided under the contract at the end of the contract term.

⁴⁰See *Kinder Morgan Power Co. v. Southern Company Services, Inc.*, 97 FERC ¶ 61,240 (2001), reh'g denied, 98 FERC ¶ 61,044 (2002) (finding Southern's interconnection procedures delayed and discriminated against customer's ability to develop new projects).

calculate available transfer capability (ATC),⁴¹ since an independent entity would have no incentive to favor one customer over another.

c. Scheduling Advantages

45. A vertically integrated transmission provider has a structural advantage over many competitors to make economy sales or to serve its own load, primarily because it has a large portfolio of both generators and loads. A competitor with access only to generation outside of the control area and no native load has to identify the delivery point of its power before being able to secure transmission service. But a vertically integrated transmission provider does not have to identify a specific location on the grid to serve its load because its load is dispersed across its entire system. A vertically integrated transmission provider also does not have to identify a single generation location, but can run a combination of its own generators or purchase from lower cost-suppliers inside or outside of its system. It can schedule purchased power to one of its own loads (in place of power from one of its own generators) in order to secure transmission service for the purchase. Later, it can find a buyer for the power and schedule transmission service from one of its internal generators to the load. This often is enough of a scheduling advantage over a competing supplier to ensure that the transmission provider (or its affiliated power marketer) gets the sale.

⁴¹The Commission used the term "Available Transmission Capability" in Order No. 888 to describe the amount of additional capability available in the transmission network to accommodate additional transmission services. To be consistent with the term generally accepted throughout the industry, "Available Transfer Capability" will be used.

46. While it is true that all network customers have these same rights and abilities, in many areas of the country the only customer using network service is the vertically integrated transmission provider. Moreover, the vertically integrated transmission provider's size of resources and loads is usually much greater than any other network customer, giving it that much more of an advantage in flexibility. In addition, the vertically integrated transmission provider may have an advantage through access to better or more transmission and other related information.

47. Under Standard Market Design, all transmission service will be provided under a new Network Access Service. Having one service for all customers will eliminate scheduling advantages of competing suppliers.

d. Imbalance Resolution

48. Customers have also alleged that vertically integrated transmission providers have an advantage over competitors in the resolution of energy imbalances. Transmission providers with generation and load of their own can resolve their own energy imbalances through in-kind energy exchanges with neighboring systems. In contrast, other customers of the transmission provider face higher costs if they take service from other suppliers that could balance against each other. This difference gives the transmission provider a competitive advantage over other sellers of power.

49. Under Standard Market Design, all suppliers and loads on a system will resolve imbalances through the same energy imbalance procedures. This will remove any

competitive advantage the transmission owner with its own generation and load may have over competing power suppliers.

e. Available Transfer Capability and Affiliates

50. Another source of discrimination is the calculation of Available Transfer Capability. A transmission provider that is not independent calculates its Available Transfer Capability, using its own proprietary data and its own equations. This discretion gives it the ability and the opportunity to discriminate in its own favor against entities that rely upon the OASIS for Available Transfer Capability information. In several cases, the Commission has found that utilities' OASIS postings reflect an inaccurate Available Transfer Capability. Indeed, in response to "serious concerns about the integrity of the postings of ATC" on the OASIS systems of two transmission providers, the Commission required the transmission providers to employ an independent third party to administer their OASIS systems.⁴²

51. Under Standard Market Design, an independent entity will calculate Available Transfer Capability and schedule transmission service. This will eliminate this potential for undue discrimination.

f. OASIS Postings

⁴²See AEP Power Marketing, Inc., et al., 97 FERC ¶ 61,219 at 61,973 (2001), reh'g pending, Docket Nos. ER96-2495-016, et al. See also American Electric Power Company, Inc. and Central and South West Corporation, 90 FERC ¶ 61,242 at 61,789 (2000) (requiring AEP to turn over its OASIS and ATC calculation functions to an independent entity as a condition of the applicants' merger). See also Appendix C for other examples.

52. Manipulation or violation of OASIS posting requirements and the Commission's standards of conduct is another way vertically integrated transmission providers that control their own OASIS sites are able to engage in undue discrimination. This can occur through prohibited off-OASIS communications between the transmission provider and its affiliated market participant, e.g., informing only the affiliate about Available Transfer Capability that will soon become available and posted on the OASIS so that the affiliate will be first in line to claim the capability.⁴³ Such abuses reinforce our belief that, in the absence of an independent entity calculating Available Transfer Capability and operating a transmission provider's OASIS, "a transmission provider's self-monitoring of its standards of conduct is not sufficient, and that it is essential for interested parties to be able to participate in this process" of reviewing communications between market participants.⁴⁴ Further, even with the best of intentions, it is not possible for a single transmission provider in a region to calculate Available Transfer Capability on its system alone without accounting for the transactions over all the other systems in its region and neighboring regions.

⁴³See *Aquila Energy Marketing Corporation v. Niagara Mohawk Power Corporation*, 87 FERC ¶ 61,328 (1999) (finding that off-OASIS communication between utility and its marketing affiliate led to preferential treatment of the affiliate); *The Washington Water Power Company*, 83 FERC ¶ 61,097 (1998) (finding favorable treatment of affiliate and expressing concern that this treatment may have been the result of prohibited off-OASIS communication).

⁴⁴*Aquila Energy Marketing Corporation v. Niagara Mohawk Power Corporation*, 87 FERC ¶ 61,238 at 62,279 (1999).

53. Similarly, control over the design, function and maintenance of OASIS systems may also present opportunities for discrimination. The Commission has been concerned for some time that transmission providers have the ability to impede competition by making their OASIS sites difficult to use, limiting users' access to OASIS and limiting access to information about transmission curtailments and interruptions that would allow the Commission to identify instances of undue discrimination.⁴⁵

54. Under Standard Market Design, an independent entity will operate an OASIS on a regional basis, and thus will remove any advantages one seller may have over another and improve the accuracy of regional Available Transfer Capability postings on the OASIS.

g. Capacity Benefit Margin Manipulation

55. The Commission has found instances of transmission providers taking advantage of their ability to reserve interface capability to serve their own load while limiting the ability of competing suppliers to access customers on its system. For instance, transmission providers have reserved excessive amounts of capacity benefit margin (CBM) to serve their own load,⁴⁶ and violated the pro forma tariff by reserving large

⁴⁵See Regional Transmission Organizations, FERC Stats. & Regs. ¶ 32,541 at 33,713 (describing market participants' perceptions that transmission providers may use OASIS to discriminate among market participants); Open Access Same-Time Information System, 64 Fed. Reg. 34,117 (June 25, 1999), FERC Stats. & Regs. ¶ 31,075 (1999) (articulating changes to Commission regulations that would make available more information about transmission curtailments and interruptions and limit OASIS hosts' ability to disconnect users).

⁴⁶See Delegated Letter in Docket No. ER98-4410-000 (Feb. 8, 1999); Entergy
(continued...)

amounts (e.g., 2,000 MW) of transfer capability at multiple interfaces, under the label of "firm import for native load," without designating resources or loads associated with the reservations as other transmission customers are required to do.⁴⁷ Import capability reserved by the transmission provider blocks a competing supplier from securing firm service across the interface, limiting that supplier's ability to compete to serve load on the system, or on neighboring systems. A related issue is whether those who set aside transmission for CBM are reserving it and paying for it under the terms of the pro forma tariff. When transfer capability for CBM is set aside for the use of one market participant, its cost is not necessarily allocated to that market participant alone. Because transmission facility embedded costs are allocated to transmission customers on the basis of use – capacity reservation for Point-to-Point Transmission Service customers and load ratio share (which does not include the transmission capability set-aside of CBM) for Network Integration Transmission Service customers – all customers may unfairly subsidize the cost of the CBM capability.

⁴⁶(...continued)

Services, Inc, 87 FERC ¶ 61,156 (1999) (directing Entergy, which had reserved 2900 MW, to recompute ATC).

⁴⁷See Aquila Power Corporation v. Entergy Services, Inc., 90 FERC ¶ 61,260, reh'g denied, 92 FERC ¶ 61,064 (2000), appeal docketed, No. 00-1417 (D.C. Cir. Sept. 22, 2000). The Commission did not order a remedy in the complaint docket since the compliance filing in Docket No. ER98-4410 to remedy the excessive native load reservations would also provide a remedy for the improper native load reservations at the interfaces. See id. at 61,860.

56. Under Standard Market Design, entities that want to reserve transfer capability must pay for that capability to reach generation reserves across an interface. Thus, the preferential treatment would be eliminated.

h. Discretionary Use of Transmission Loading Relief

57. The opportunity for anticompetitive behavior arises when transmission providers have discretion to dispatch their own generation to serve their own load in a way that requires transmission service curtailments through the use of transmission loading relief (TLR) procedures.

58. There has been a sharp increase in the number of TLRs used in some regions, suggesting that transmission operators rely upon them to do more than simply relieve emergency transmission overloads.⁴⁸ There are unmistakable financial incentives to rely on TLRs in forward transmission planning:

The increased incidence of TLRs may suggest that some transmission capacity is being oversold. Market participants have attributed a tendency to implement a greater number of TLRs to the commercial reality that transmission providers do

⁴⁸In the Southeast, the incidence of TLRs increased 354 percent from the summer of 1999 to the summer of 2000. See Staff Report to the Federal Energy Regulatory Commission on the Bulk Power Markets in the United States (Nov. 1, 2000), available in <<http://www.ferc.gov/electric/bulkpower/southeast.pdf>>, at 3-38. In the Midwest, the incidence increased 472 percent over the same time period. See Staff Report to the Federal Energy Regulatory Commission on the Bulk Power Markets in the United States (Nov. 1, 2000), available in <<http://www.ferc.gov/electric/bulkpower/midwest.pdf>>, at 2-32. The lack of a centralized market, particularly in the Southeast, has limited market liquidity and, thus, increased the likelihood of TLRs.

not have to refund transmission reservation fees for service curtailed because a TLR is called.^[49]

59. When a vertically integrated transmission provider injects power from its own generation onto its own power lines to meet the constantly shifting demands of the load on its system, it has both the opportunity and the incentive to manipulate the transmission system for its own benefit. It can either dispatch generators to create a transmission constraint that prevents a competitor from making a sale that the transmission provider would also like to make, or it can capitalize on legitimate constraints into a load pocket to curtail a competitor's transmission transaction and serve the customer with its own generation instead. The key here is that none of the transmission provider's actions require direct communication with its merchant function or marketing affiliate. A simplified hypothetical example of such anti-competitive behavior is set forth in Appendix C.

60. Several aspects of our proposed remedy address this concern, including the use of LMP to manage congestion and the requirement that transmission facilities be operated by an Independent Transmission Provider.

2. Lack of Common Rules Governing Transmission

⁴⁹Staff Report to the Federal Energy Regulatory Commission on the Bulk Power Markets in the United States (Nov. 1, 2000), available in <<http://www.ferc.gov/electric/bulkpower/southeast.pdf>> at 3-39.

61. Some of the difficulties that come from having different rules as power moves across the grid are discussed later in the Seams Problems Section III.B.4), where a "seam" is a dividing line between different sets of grid rules.

62. Having two or more different sets of rules governing the operation of a transmission system makes it difficult – if not at times impossible – for that system to support an efficient regional electric power market. If the interstate transmission system is to provide fair and efficient movement of power on behalf of all users of the system, the same general rules must govern such matters as who gets service, who has the right to transmission service when not all service requests can be accepted, how the transmission facility costs are allocated among transmission customers, who gets its transmission curtailed and by how much when a transmission outage prevents all the planned services from being accommodated, who plans the additions to the grid and who pays for these additions.

63. Today there are not only different rules in different public utility systems, but there may be more than one set of rules for transmission owned by a single utility. This is because there are different rules for two types of wholesale transmission service, and the rules for bundled retail transmission service may differ from the rules for wholesale and unbundled retail transmission services.

64. The Commission established an open access transmission tariff under Order No. 888 that provides for two distinct types of wholesale transmission services – Network Integration Transmission Service and Point-to-Point Transmission Service. Network

Integration Transmission Service was designed primarily to meet the needs of the transmission customer that wants to integrate many generators and many loads at diverse locations on the public utility's grid; it was intended to be comparable to the service that the public utility provided to its own bundled retail customers. Point-to-Point Transmission Service, as the name implies, was designed primarily for the customer that wants to move power from one discrete location to another.

65. At the time Order No. 888 issued, the Commission recognized the potential for problems with having two wholesale services that could not be truly equal, especially the problem of dealing with claims of undue discrimination between the services.

Consequently, along with the issuance of Order No. 888 the Commission proposed a rule to create a new tariff, called the Capacity Reservation Tariff.⁵⁰ It was intended to remedy the anticipated problems by establishing a new tariff that would replace the two wholesale services with one. The Commission received many comments on the proposed rule and held a technical conference with representatives of diverse stakeholders.⁵¹

66. Some parties expressed concern about moving quickly to a single service based on the Capacity Reservation Tariff model, while other parties asserted that, although a single

⁵⁰See Capacity Reservation Open-Access Transmission Tariffs, 61 Fed. Reg. 21,847 (May 10, 1996), FERC Stats. and Regs. ¶ 32,519 (1996) (Notice of Proposed Rulemaking).

⁵¹See Capacity Reservation Open-Access Transmission Tariffs, 76 FERC ¶ 61,065 (1996) (notice extending deadline for filing written comments and convening technical conference).

tariff reducing the two services to one was a good policy, there were problems with the particular Capacity Reservation Tariff that was proposed. They recommended that the Commission delay acting on the proposed rule until it learned the best form of single service tariff through industry experience with open access. This is the approach that the Commission in effect followed. Since the two Order No. 888 services were adopted, however, there have been allegations of undue discrimination between customers of the two services as discussed later in this section.

67. There are also different rules for bundled retail transmission service and for wholesale and unbundled retail transmission services. States have historically established the rules for the transmission component of bundled retail transactions, while the Commission has established the rules for wholesale and unbundled retail transmission services.

68. Despite the requirement in Order No. 888 that no transmission customer may have any undue advantage over another, there remain real or perceived advantages for the customers of vertically integrated transmission owners. In many cases, the perceived advantage is one of Network Integration Transmission Service over Point-to-Point Transmission Service, where Network Integration Transmission Service is available to both bundled retail transmission customers and wholesale Network Integration Transmission Service customers, while Point-to-Point Transmission Service is taken primarily for wholesale transmission by independent power producers and marketers.

69. Four prominent examples highlight the alleged advantages that a public utility's bundled retail customers have over wholesale and unbundled retail customers. First, certain reliability practices related to keeping the transmission system balanced may allow a public utility that is responsible for keeping generation and load in balance to obtain lower costs for its own power customers. Second, a transmission-owning public utility may have more de facto flexibility to designate transmission receipt and delivery points than other transmission customers, if that public utility also provides power to customers on its transmission system. Third, the bundled retail customers of a transmission owner may have certain transmission reservation and pricing advantages regarding transmission transfer capability set aside for reliability. Fourth, state transmission curtailment rules that favor a public utility's bundled retail customers may conflict with the Commission's transmission curtailment rules, resulting in a transmission preference to customers in one state over customers served in other states.⁵² The first three of these were summarized above, and a detailed discussion with examples is set forth in Appendix C.

70. The requirement for all services on the transmission grid to be taken under a common set of rates, terms and conditions will resolve these concerns.

3. Congestion Management

71. Due to new transmission usage patterns and the lack of transmission infrastructure improvements, congestion has increased. However, economically sound congestion

⁵²We emphasize that transmission curtailment does not necessarily mean a power outage.

management plans do not exist in most parts of the country, and transmission customers have been exposed to transmission service interruptions and increasing generation costs due to the risk of interruption. The operating rules that do exist were not designed as a congestion management tool for allocating scarce transmission capacity, but were designed to keep facilities from overloading in an emergency, such as when a transmission facility unexpectedly goes out of service.

72. Currently, under the existing pro forma tariff, congestion is managed primarily through a system of physical reservation of capacity, based on each individual transmission provider's calculation of the Available Transfer Capability of its grid, a calculation often made without knowledge of the power flows on its grid that result from transactions scheduled over other grids in its region. Under the current pro forma tariff, customers reserve capacity on either a firm or non-firm basis, based on the assumed contract path that the transaction will use. Once the customer has reserved capacity on a firm basis, it is supposed to receive certainty both that power will be delivered and the price that the customer will be charged for transmission. If the customer has non-firm capacity, it has no certainty that capacity will be available to deliver power, but does know that there will be no congestion charge if the delivery does occur.

73. The existing pro forma tariff also provides that the redispatch of a transmission provider's generating units to relieve congestion is required only if it can be achieved while maintaining reliable operation of the transmission system in accordance with prudent utility practice. The recovery of the higher generation costs resulting from such

generator redispatch, which are a subset of opportunity costs, requires that (1) a formal generator redispatch protocol be developed and made available to all transmission customers and (2) all information to calculate redispatch costs be made available to the customer for audit. If a transmission provider collects revenues to cover the redispatch costs from a specific transmission customer, it must credit these revenues to the cost of fuel and purchased power expense included in its wholesale fuel adjustment clause.

Various tariff provisions specify how redispatch is to be implemented. For instance, Sections 33.2 and 33.3 of the existing pro forma tariff provide that the redispatch of all network resources and the transmission provider's own resources, on a least-cost basis without regard to ownership, is to be performed only to maintain system reliability, not for economic reasons. Under those circumstances, the redispatch costs would be shared among the network customers and the transmission provider on a load ratio basis.

Sections 13.5 and 27 of the existing pro forma tariff permit the transmission provider to provide the requested transmission service and relieve a system constraint by redispatching the transmission provider's resources: (1) if this costs less than constructing network upgrades; and (2) if, under Section 13.5, the transmission customer agrees to compensate the transmission provider for any such redispatch costs on an incremental basis as specified in the customer's service agreement prior to the commencement of service.

74. Although the existing pro forma tariff allows the recovery of generating unit redispatch costs, the Commission generally has not accepted proposals submitted by

single-utility transmission providers to recover such costs. For instance, the Commission rejected Bangor Hydro-Electric Company's (Bangor Hydro) proposed formula to recover opportunity costs for lack of supporting data showing that its opportunity cost pricing would be consistent with the principle of comparability and because the formula lacked sufficient detail to operate as a rate formula itself.⁵³ The Commission directed Bangor Hydro to submit a separate section 205 filing with revised opportunity cost pricing before implementing such pricing. The Commission also rejected a proposal by the operating companies of Central and South West Corporation (CSW) regarding redispatch costs because they did not provide sufficient specificity to enable a customer to calculate or verify redispatch costs and because the formula lacked sufficient detail to operate as a formula rate.⁵⁴ The Commission also directed CSW to submit a separate filing under section 205 before implementing such pricing.

75. Because it is difficult for a single-utility transmission provider to develop a formula that specifies the costs of redispatch and protects transmission customers' interests, generation redispatch has not been used as extensively as it could be used to relieve congestion. A transmission provider will not redispatch generating units if it cannot collect its higher generation costs, and less transmission transfer capability will be available to the energy market.

⁵³See *Allegheny Power System, Inc., et al.*, 80 FERC ¶ 61,143 (1997).

⁵⁴*Central Power and Light Company*, 81 FERC ¶ 61,311 (1997).

76. In 1998, the Commission called on public utilities to work with the North American Electric Reliability Council (NERC) to develop a congestion management system based on redispatch.⁵⁵ NERC responded with its pilot Market Redispatch program that relied on counterflow transactions, i.e., power transfers against the prevailing flows on the constraint, to relieve the congestion.⁵⁶ Although the program has been in place for several years, it has been implemented only infrequently because of the difficulty in establishing counterflow transactions and the limited availability of data to the transmitting customer.⁵⁷

77. In 1998, Commonwealth Edison Company (ComEd) proposed a similar voluntary redispatch program, which predated NERC's Market Redispatch Program.⁵⁸ In

⁵⁵The NERC rules for protecting the system were designed to adapt the Commission's Order No. 888 individual utility transmission curtailment requirements to multi-system transactions and parallel flows. See North American Electric Reliability Council, 85 FERC ¶ 61,353, 62,363-64 (1998).

⁵⁶See North American Electric Reliability Council, et al., 87 FERC ¶ 61,160 (1999).

⁵⁷NERC identified several problems with the program in a January 31, 2002 submittal to the Commission: (1) the Market Redispatch customer cannot easily anticipate and specify in advance which facilities will overload and require transmission curtailment; (2) the Market Redispatch transaction must provide a counterflow for the entire protected transaction even though the required transmission curtailment may be only a portion of the original protected transaction; and (3) the Market Redispatch customer cannot easily discover the availability of generator pairs for counterflow transactions. See Report on Market Redispatch Pilot Program by NERC Market Interface Committee and Motion to Continue Market Redispatch Program, Docket No. ER02-933-000, at 3 (Jan. 31, 2002).

⁵⁸See Commonwealth Edison Company, et al., 83 FERC ¶ 61,145 (1998).

November 1998, ComEd submitted the first of two interim reports to the Commission summarizing its experience with the program.⁵⁹ It determined that a single utility cannot effectively offer redispatch over other systems, especially where other generation owners do not participate.

78. The overall result of the Order No. 888 congestion management system is that the transmission system is not utilized in the most efficient manner. Customers can be denied access to lower-cost supplies that could be made available if the congestion management and pricing system had an efficient and fair method of recovering the cost of generator redispatch.

79. Managing congestion using an LMP system, coupled with a single transmission service that relies on price (rather than first-come, first-served) to allocate limited transmission capacity, will resolve these problems.

4. Seams Problems

80. A lack of common transmission rules inhibits competition in power markets not only when there are different rules for different customers under one public utility's tariff or one RTO's tariff, but also when there are different rules from one public utility to the next, or from one RTO to the next. The term "seam" has come into common use in the electric power industry over the last several years to refer to a boundary between areas

⁵⁹Interim Report on Non-Firm Redispatch, Docket No. ER98-2279-000 (Dec. 17, 1998).

with different transmission or other market rules. Market participants assert that it can be difficult to move power "across a seam" from one area to another.

81. Seams issues include differences in transmission rules as well as differences in power market rules. They include such diverse matters as different operating rules (e.g., rules for recalling firm transmission capacity; coordination of generation and transmission maintenance schedules; how parallel path flows are determined to affect other regions); different market rules (e.g., bidding rules; market product definitions); different market designs (e.g., congestion management procedures; demand response rules; market price intervention practices); different business practices (e.g., scheduling practices; reservation practices; OASIS designs; processes to verify transactions between ISOs and market participants; transmission and generation outage information dissemination, compensation, and coordination rules; generation interconnection practices; liability provisions); and different electronic and telephonic communications protocols.

82. Market participants have called for a "seamless market," by which they mean a market whose operation is not encumbered by differences in rules at public utility or RTO boundaries. To achieve a seamless market, some assert that rules may differ but only in ways that the differences are invisible to power sellers and buyers. Others assert that such management of differences rarely works in practice and that the rules must be the same everywhere to achieve a seamless market.

83. The Commission has long recognized the need for more coordination and uniformity throughout a region in transmission matters. Our Regional Transmission

Group Policy Statement of 1993⁶⁰ encouraged public utilities to develop a common set of rules for regional expansion planning, and our Transmission Pricing Policy Statement of 1994⁶¹ encouraged the development of a common pricing policy for a region that would internalize and rationalize the pricing of parallel path flows. As explained above, Order Nos. 888 and 2000 recognized the need to bring the various public utility transmission systems in a region under a common set of transmission rules. Order No. 888 not only applied a common set of open access transmission rules to public utility transmission systems, but included a reciprocity provision that conditioned a non-public utility's use of a public utility's open access transmission tariff on the non-public utility's agreement to provide comparable transmission service to the public utility. Indeed, Order No. 888 also encouraged the formation of ISOs not only to bring all the transmission systems in a region under common rules, but also under unified operation. Many parties in Canada have stressed the necessity of having a common set of rules for reliability and trading protocols for cross-border transmission facilities.⁶² Order No. 2000 built on this theme

⁶⁰Policy Statement Regarding Regional Transmission Groups: Policy Statement, 58 Fed. Reg. 41,626 (August 5, 1993), FERC Stats. & Regs. ¶ 30,976 (Jul. 30, 1993).

⁶¹Inquiry Concerning the Commission's Pricing Policy for Transmission Services Provided by Public Utilities Under the Federal Power Act, 59 Fed. Reg. 55,031 (November 3, 1994), FERC Stats. & Regs. ¶ 31,005 (Oct. 26, 1994), order on reconsideration and clarifying policy statement, 71 FERC ¶ 61,195 (1995).

⁶²See, e.g., Ambassador Michael Kergin (Canada) letter to Honorable Thomas A. Daschle, Senate Majority Leader, dated November 2, 2001:

Canadian electricity companies are linked to their counterparts in the
(continued...)

by strongly encouraging the formation of RTOs to bring all facilities in a region under a common set of transmission rules. However, RTOs have not developed at the pace anticipated when Order No. 2000 was issued and seams problems continue to exist. In June 2001, the Commission held a technical conference on seams issues.⁶³ Participants to the seams conference explained that resolution of seams issues is critical for making the inter-RTO transmission systems and power markets work.

84. We set forth in Appendix C a number of examples of differences in rules that can create seams problems, and a discussion of efforts at the Commission or within the industry to address seams problems.

85. The requirement under Standard Market Design for a single tariff and a single market design operating with the same set of rules throughout the entire interconnection resolves the seams problems discussed above.

⁶²(...continued)

U.S. through a number of major connections crossing our common border. We share a truly international electricity grid. This interconnectedness itself enhances our respective energy security, but it also places an onus on our countries to act together to manage the grid. Nowhere is that more important than in the area of electricity reliability. . . . Because uniformity in reliability standards is required to enable effective electricity trade, variations in standards would impede electricity trade and balkanize markets.

⁶³Conference on RTO Interregional Coordination, Docket No. PL01-5-000, June 19, 2001. Called by many the "FERC Seams Conference," this technical conference on the RTO interregional coordination requirements of Order No. 2000 helped the Commission learn about seams issues and about how uniform standards for some rules could benefit power markets.

5. Market Design Flaws

86. Poorly designed market rules, or market rules with unforeseen or unintended consequences, can have a debilitating effect on markets, market pricing and overall confidence in the markets of the market participants. Moreover, differences in market designs in neighboring regions can also lead to problems such as the exercise of market power through the exploitation of the differences.

87. Wholesale electricity markets are complex, with multiple products traded at multiple locations on different time-frames, while subject to the unique physical characteristics of electricity (e.g., non-storable, need for system stability and balancing, physics of power flows). Market rules have been affected by the variation in generation mix, the transmission network layout and the local and regional regulatory history in different regions of the country. For example, the initial California markets had a design quite different from the designs of the markets in the Northeast region (PJM, New York and New England).

88. In the regions where voluntary, organized ISO markets for energy, transmission and ancillary services have been established under the existing tariff, problems due to the design choices have been characterized as "market design flaws." A market design flaw is a market rule – including product specification, bid format, auction rules and pricing rules – that allows distortions in the market prices or availability of a product or service, whether energy, ancillary services, transmission service or installed capacity. In the years since the ISO markets have been operating, dozens of market design flaws have been

identified, ranging from minor problems that cause temporary inconveniences to major problems that require markets to be re-designed. No region has been exempt from market design flaws of one type or another. We set forth in Appendix C examples of specific design flaws.

89. These problems have resulted in markets that are inefficient and do not produce the lowest reasonable prices for electric power. These problems cannot be resolved on a case-by-case basis because that will maintain and exacerbate the problems due to local differences in rules. Only standardization of electricity market design will solve these problems. In the parts of the country in which markets are most mature, including the Northeast, Midwest and California, there is broad consensus on the principal elements of market design and business practices. A standard market design rule will help advance this process and extend it to other regions. Our goal is to use the Standard Market Design rulemaking to address and remedy many of the market design flaws identified to date and to raise the quality of all electric markets simultaneously.

90. Market rules will need to be flexible and have the ability to evolve over time. However, consistent rules across the entire interconnection based on best practices, coupled with sound market monitoring to promptly identify and correct any design flaws will provide the necessary foundation for future market innovation and improvement.

C. Reform Essential Given the Changed Nature of the Electric Industry

91. The need to address the instances of discrimination described above is all the more critical given the changing nature of the electric industry. The United States electric power industry is in the middle of a transition from a predominantly monopoly industry to a predominantly competitive industry. The fundamental economic driver of change has been, and continues to be, the reduction of economies of scale in new generation construction, combined with environmental restrictions that encourage gas-fired units. This is due in large part to the introduction during the 1980s of highly efficient gas turbines and combined cycle generators that produce much more electricity from a given amount of gas. A relatively small gas-fired generator can compete effectively with power from a large central generating station. Additionally, small distributed generation is becoming economic, and some renewable energy resources, especially wind power generation, are also on the verge of becoming competitive.⁶⁴ In the right locations, wind generating units can compete with the much larger coal, nuclear and hydroelectric units.⁶⁵

92. Because of these fundamental changes in industry technology, small producers of electricity can compete with large producers, and both the smaller utilities and the retail customers of a number of utilities have demanded access to competing power suppliers in hopes of lowering their electric bills, improving service and harnessing new technologies.

⁶⁴See, e.g., International Energy Agency, *Distributed Generation in Liberalized Electricity Markets*, International Energy Agency (June 2002); and Ann Chambers, *et al.*, *Distributed Generation: A Nontechnical Guide* (PennWell Corp. 2001).

⁶⁵See Christine Real de Azua, *Wind Power: Poised for Take Off? A Survey of Projects and Economics*, Pub. Util. Fort., Aug. 2001 at 38.

The pressures for retail access have been greater in regions with higher rates, which are typically regions with few low-cost natural resources for generating electric power, such as nearby coal mines, gas fields, and hydroelectric areas.⁶⁶ Many of these regions have taken the lead in retail restructuring, while regions with historically low electricity production costs have proceeded more cautiously or even affirmatively decided not to change their retail access policies or to support their local utilities' participation in regional programs at this time.⁶⁷

93. One hallmark of electric industry restructuring has been the growth of wholesale trade. In the past, wholesale power purchases made up a small fraction of a large vertically integrated utility's power supply, with most of its power needs met by its own generation. Today, however, even large vertically integrated utilities rely increasingly on wholesale purchases for their energy supplies. For example, as shown in Table 1, between 1989 and 2000, generation by investor-owned utilities grew from 2,132 thousand GWh to 2,230 thousand GWh, an increase of less than 5 percent. During this time, wholesale power purchases by these utilities almost tripled. Table 1 also shows that in 1989 wholesale power purchases provided 18 percent of the total electric energy available to investor-owned utilities from both wholesale purchases and their own generation. By

⁶⁶See Energy Information Administration, *The Changing Structure of the Electric Power Industry 2000: An Update*, at 81-82 (2000), available in <http://www.eia.doe.gov/cneaf/electricity/chg_stru_update/update2000.pdf> (hereinafter *Electric Power Industry 2000 Update*).

⁶⁷See id.

2000, wholesale purchases provided over 37 percent of investor-owned utility electric energy. This percentage has steadily increased since 1989, and is expected to continue to grow as utility-owned plants are sold or retired and new power supplies are acquired competitively in most parts of the country.

**Table 1. Investor-Owned Utilities' Total Purchases, 1989 - 2000,
As a Percentage of Energy Purchased and Self-Generated**

Year	IOUs' Purchases (GWh)	IOUs' Generation (GWh)	<u>Purchases</u> (Purchases + Generation) (%)
1989	460,627	2,132,065	17.8
1990	530,325	2,134,429	19.9
1991	635,015	2,145,435	22.8
1992	671,758	2,143,847	23.9
1993	718,876	2,216,724	24.5
1994	732,710	2,237,652	24.7
1995	786,676	2,269,958	25.7
1996	916,087	2,308,156	28.4
1997	1,080,538	2,321,225	31.8
1998	1,073,638	2,402,571	30.9
1999	1,083,892	2,353,639	31.5
2000	1,324,558	2,229,617	37.3

Source: RDI POWERDAT Database

Note: Data for 2001 is not yet available. Investor-owned utility purchases include purchases from affiliates.

94. Table 1 demonstrates the increasing importance of competitive wholesale energy acquisition in the United States electric power industry, and the need for this Commission to ensure that transmission, market rules and institutions are reformed as necessary to support the new environment. It also makes clear that a retreat from competitive markets

to a cost-regulated vertically integrated world would be difficult – the nation now depends increasingly on wholesale interstate electricity markets.

95. Similar data are presented in Tables 2 and 3 for large public power utilities and generation and transmission cooperatives that generate at least some of their own power.⁶⁸ These tables show that wholesale purchases, on average, provide about 40 percent of the power needs of these large utilities. Data are not presented for the smaller public power and cooperative utilities because they typically do not self-generate but buy all of their power at wholesale.

⁶⁸Note that the data available for large public power and cooperative utilities is not complete but represents a sampling of these utilities. The sample size typically grew each year so that an apparent growth in the wholesale purchase percentages could reflect the addition of smaller utilities that purchase more power at wholesale.

Table 2. Large Public Power Utilities' Total Purchases, 1992 - 2000, As a Percentage of Energy Purchased and Self-Generated			
Year	Utilities' Purchases (GWh)	Utilities' Generation (GWh)	<u>Purchases</u> (Purchases + Generation) (%)
1992	297,076	520,348	36.3
1993	314,472	549,810	36.4
1994	331,643	555,198	37.4
1995	332,962	586,737	36.2
1996	350,880	645,740	35.2
1997	349,641	674,725	34.1
1998	364,434	676,698	35.0
1999	394,617	634,548	38.3
2000	429,369	631,143	40.5
Source: RDI POWERDAT Database.			

"Large Public Power Utilities" includes municipals, federal power authorities.
Data for 2001 is not yet available.

**Table 3. Generation & Transmission Cooperatives' Total Purchases, 1992 - 2000
As a Percentage of Energy Purchased and Self-Generated**

Year	Cooperatives' Purchases (GWh)	Cooperatives' Generation (GWh)	<u>Purchases</u> (Purchases + Generation) (%)
1992	85,226	136,417	38.5
1993	93,756	149,783	38.5
1994	96,148	156,589	38.0
1995	99,909	166,099	37.6
1996	117,455	172,161	40.6
1997	112,822	176,689	39.0
1998	115,003	177,534	39.3
1999	122,151	172,323	41.5
2000	127,785	171,198	42.7

Source: RDI POWERDAT Database.

Note: "Generation & Transmission Cooperatives" includes cooperatives with generation and transmission facilities, but excludes distribution cooperatives. Data for 2001 is not available yet.

96. The transition to competitive electricity markets is characterized by opportunity and uncertainty. The promise of competition is the opportunity to develop more innovative technologies, improve services, lower average electric rates and provide more customer choice than is likely under a strictly regulated monopoly environment. During the transition to competition, these promises are only partly fulfilled, and results vary regionally as a result of different choices about retail restructuring. Additionally, the California electricity crisis of 2000-2001, allegations of improper trading practices, the collapse of Enron Corporation in December 2001 and the deteriorating financial health of

many electric suppliers and marketers at this time have added unprecedented uncertainty about, and lack of confidence in, today's electric markets.

97. In addition to general concerns about adequate constraints on the exercise of market power by power sellers, there is uncertainty in the industry about impediments to new generators entering the market, adequacy of incentives to build much needed generation and transmission infrastructure, availability of non-discriminatory transmission service for all sellers and buyers in a regional market and the risk of making long-term commitments when market rules are subject to frequent experiment and change. Differences in market rules between regions make it difficult to transact business across regions and thus also lead to increased uncertainty in the industry and the risk of market manipulation.

98. Investors, generators and transmission providers are reluctant to invest in new generation and transmission infrastructure if the rules for setting energy or transmission prices are not yet known or are subject to frequent revision.⁶⁹ Thus, uncertainty about the direction of competition policies inhibits the development of the very infrastructure needed both to allow competition to work and to assure reliability in a competitive environment. Customers are reluctant to sign contracts for power or to change suppliers

⁶⁹See generally U.S. Department of Energy, National Transmission Grid Study (May 2002), available in <<http://tis.eh.doe.gov/ntgs/>> (hereinafter DOE National Transmission Grid Study).

if long-term power markets are unnecessarily volatile and they cannot obtain price certainty.

99. The promise of wholesale competition may go unfulfilled – or at best continue to be delayed at great cost – unless many of these uncertainties are resolved. This proposed rule is intended to help resolve generically many of the uncertainties facing the electric power industry and to restore confidence in future power markets.

D. Legal Authority and Findings

100. The primary purposes of the Federal Power Act are to curb abusive practices by public utilities and to protect customers from excessive rates and charges. To achieve these ends, section 205 of the Federal Power Act requires that no public utility shall "make or grant any undue preference or advantage to any person or subject any person to any undue prejudice or disadvantage," with respect to the transmission of electric energy in interstate commerce or wholesale sales.⁷⁰ Section 206 of the Federal Power Act authorizes the Commission to investigate and remedy unduly discriminatory or preferential rules, regulations, practices or contracts affecting public utility rates for transmission in interstate commerce and for sales for resale of electric energy in interstate commerce.⁷¹ It also authorizes the Commission to investigate and remedy unjust and

⁷⁰16 U.S.C. 824d.

⁷¹16 U.S.C. 824e.

unreasonable rates, charges or classifications, and any rules, regulations, practices or contracts affecting such rates, charges or classifications.

101. Moreover, the Commission's regulatory authority "clearly carries with it the responsibility to consider, in appropriate circumstances, the anticompetitive effects of regulated aspects of interstate utility operations pursuant to [Federal Power Act sections] 202 and 203, and under like directives contained in [Federal Power Act sections] 205, 206, and 207."⁷² The Commission's authority to remedy undue discrimination and anticompetitive effects is broad.⁷³

102. The Court of Appeals for the District of Columbia Circuit reviewed challenges to Order No. 888 and found that the "open access requirement is authorized by and consistent with the [Federal Power Act]," and upheld the order.⁷⁴ On appeal, the Supreme Court affirmed the Commission in applying its open access requirements to transmission used for wholesale and unbundled retail sales of electric energy in interstate commerce, but also concluded that the Commission had jurisdiction over transmission used for bundled retail sales of electric energy in interstate commerce. The Supreme

⁷²See Order No. 888 at 31,669 (quoting *Gulf States Utilities Co. v. FPC*, 411 U.S. 747, 758-59, reh'g denied, 412 U.S. 944 (1973)). See also *City of Huntingburg v. FPC*, 498 F.2d 778, 783-84 (D.C. Cir. 1974) (finding that the Commission has a duty to consider the potential anticompetitive effects of a proposed interconnection agreement).

⁷³See Order No. 888 at 31,669 (the Federal Power Act fairly bristles with concern for undue discrimination (citing *Associated Gas Distributors v. FERC*, 824 F.2d 981, 998 (D.C. Cir. 1987), cert. denied, 485 U.S. 1006 (1988))).

⁷⁴*Transmission Access Policy Study Group v. FERC*, 225 F.3d at 685.

Court further stated that the Commission may regulate bundled retail transmission of energy as a means of addressing undue discrimination. While the Court did not adopt the appellants' suggestions that the Commission's finding of discrimination in the wholesale electricity market suggested the presence of discrimination in the retail electricity markets,⁷⁵ it stated that "[w]ere FERC to investigate this alleged discrimination and make findings concerning undue discrimination in the retail electricity market, § 206 of the FPA would require FERC to provide a remedy for that discrimination. . . . And such a remedy could very well involve FERC's decision to regulate bundled retail transmissions" of energy.⁷⁶

103. We find that undue discrimination and anticompetitive behavior persist, as detailed in Section III and Appendix C, in both wholesale and retail transmission of energy.

Pursuant to our statutory mandate to remedy undue discrimination and anticompetitive effects in these markets, as interpreted by the Supreme Court, we will apply the requirements of this rule to the transmission component of bundled retail transactions. At a minimum, all transmission service in interstate commerce must be subject to the same non-discriminatory non-rate terms and conditions in order to eliminate undue discrimination in wholesale markets and in retail choice markets. With respect to rates

⁷⁵See id. at 1028.

⁷⁶Id.

for bundled retail transmission service, however, we will work with states to address difficult transition rate issues.

104. In light of these statutory responsibilities and authorities under the Federal Power Act, we have assessed the state of the electric utility industry and determined that it is necessary to act promptly to provide stability to the industry and to assure that customers receive adequate supplies of electric energy at the lowest reasonable price. During the past six years, the implementation of open access transmission under Order No. 888 has fundamentally altered the landscape of the electric utility industry by removing major discriminatory barriers to the use of the interstate transmission grid and thereby opening the door to competition in wholesale electric power markets. However, even with the Order No. 888 open access pro forma transmission tariff and Order No. 889 transmission standards of conduct in place, there continues to be undue discrimination in the provision of interstate services. Experience under the pro forma tariff has demonstrated that unduly discriminatory transmission practices continue today. Further, existing trading rules and design of wholesale power markets do not consistently prevent market manipulation or send proper price signals to participants or allocate scarce resources to those who value them most and thus could result in unjust and unreasonable rates. Thus, competition either does not exist in many areas of the country or competition is distorted.

105. We find that:

- (1) the operation of the Commission's pro forma transmission tariff (which is administered by vertically integrated as well as non-vertically integrated

- public utilities such as ISOs) contains provisions that, in practice, permit undue discrimination in the provision of transmission services;
- (2) public utilities that own, operate or control transmission facilities and also participate in power markets continue to possess substantial transmission market power and retain the ability to unduly discriminate in the provision of transmission service and spot market energy services;
 - (3) lack of standardized wholesale electric market design allows undue discrimination within and across regions, can result in unjust and unreasonable pricing and allocation of transmission and permits the exercise of market power (and thus unjust and unreasonable rates) in power markets; and
 - (4) proper price signals are not being sent to the marketplace, with the result that market-based rates in many places are distorted, and reasonably accurate price signals necessary for infrastructure additions are not being sent.

106. To remedy remaining undue discrimination in the provision of interstate transmission services and in other industry practices, and to ensure just and reasonable rates for sales of electric energy within and among regional power markets, the Commission proposes to modify the Order No. 888 pro forma tariff to reflect non-discriminatory, standardized transmission service and require standardized wholesale

electric market design. The Commission also proposes to expressly exercise jurisdiction over all transmission in interstate commerce by public utilities.

IV. THE PROPOSED REMEDY

107. The Commission's goal in Order Nos. 888 and 2000 was to harness the benefits of competition for the nation's electricity customers by assuring adequate and reliable supplies of electricity at a just and reasonable price. As discussed above in the Need for Reform section (Section III), the current rules and regulations have prevented the full attainment of that objective. To address these problems in the current system, we are proposing a comprehensive package of reforms that are described more fully in this section.

108. Section III and Appendix C provide numerous examples of ways that an entity that owns both transmission and generation can discriminate in favor of its own customers or generation under the current tariff. The problem stems from the differences in the sets of rules that apply to users of the transmission system. First, the current regulatory system allows vertically integrated utilities to discriminate in favor of their bundled retail load at the expense of wholesale customers. This occurs because transmission service for bundled retail customers is subject to different rules and rates than service for wholesale customers. Second, the current distinction between Point-to-Point Transmission Service and Network Integration Transmission Service also creates opportunities for undue discrimination in favor of generation owned by the transmission owner or an affiliate.

109. To remedy this discrimination we propose to place all transmission customers under the same set of rules. We propose to place transmission service for bundled retail customers under the same terms and conditions of service as wholesale transmission service. To accomplish this we propose to revise the existing pro forma tariff to remove provisions that grant preferential treatment to transmission service for bundled retail customers. We propose that all public utilities that own, control or operate interstate transmission file these interim changes no later than July 31, 2003. We also propose that no later than September 30, 2004, or such date as the Commission may establish, only Independent Transmission Providers would operate Commission-jurisdictional facilities. This requirement will apply whether or not the public utility that owns, controls or operates interstate transmission facilities has joined an RTO.⁷⁷ We are proposing specific governance requirements that must be met by the Independent Transmission Provider.

110. Also, no later than September 30, 2004, or such date as the Commission may establish, we propose to eliminate the distinction between Point-to-Point and Network Integration Transmission Services by having one service, Network Access Service, that contains elements of both types of service – the flexibility of Network Integration Transmission Service and the tradability of Point-to-Point Transmission Service. We propose these time periods to provide sufficient time for the development of the necessary new software systems. Network Access Service is based on an open spot market for

⁷⁷A Commission-approved RTO would meet the requirements of an Independent Transmission Provider.

imbalance energy and a uniform congestion management methodology, i.e., LMP, to more efficiently manage the transmission grid. The spot energy market and LMP rely on management of the transmission system and bidding by supply and demand resources attached to the transmission grid under market rules and protocols.

111. To provide the price signals needed to manage congestion, the Independent Transmission Provider will be required to operate a day-ahead and real-time market for energy. To provide customers with a mechanism for achieving price certainty under the new congestion management system, we also propose to require that customers be given Congestion Revenue Rights for their historical uses that protect against congestion costs when specific receipt and delivery points are used.

112. LMP and Congestion Revenue Rights will provide price signals to indicate where new investment is needed; however, the price signals alone may not guarantee sufficient investment. We also propose to require a regional transmission planning and expansion process to provide a backstop process for ensuring that needed transmission construction is undertaken. We propose that this process begin six months from the effective date of the Final Rule, even though much of the country will not have had the opportunity to respond to LMP and Congestion Revenue Rights for another few years.

113. At this stage of the industry's evolution, structural barriers to competitive markets remain, so to address this we are proposing market power mitigation measures for the spot markets that will be operated by the Independent Transmission Provider. These measures are designed to address the two significant structural problems in wholesale

energy markets – the existence of localized market power that arises from transmission constraints, and the lack of price-responsive demand. The market power mitigation proposal is a framework that can be tailored to reflect the competitive conditions of the particular region. It is designed to be reexamined annually and adjusted as needed to reflect changes in the competitive structure of the region, including a phasing out of mitigation measures as resource adequacy and demand response develops. Because market power mitigation of spot market prices will tend to suppress the price signals for new entry, we are also proposing a non-price mechanism to assure that load meets a long-term resource adequacy requirement.

114. To avoid the market design flaws discussed in the Need for Reform section (Section III) and Appendix C and market manipulation in Appendix E, and to minimize the potential for seams issues, we propose a standardized tariff that incorporates the best practices and builds on the lessons from our experience with organized markets. In Appendix B, the proposed SMD Tariff standardizes many aspects of the basic market design. However, it also allows flexibility in a number of areas to customize the basic market design to meet regional requirements where such customization will not lead to further discrimination or inefficiencies.

115. We propose to permit small entities to seek waiver of the Standard Market Design Final Rule requirements. The regulations we propose include waiver provisions under which public utilities, and non-public utilities seeking exemption from the reciprocity condition, may file requests for waivers from all or part of the Commission's regulations.

116. Finally, while we have attempted to standardize the basic aspects of the market design policy, this proposed rule does not include detailed business practices and communication protocols that will be needed to administer Standard Market Design. We fully appreciate the benefits of business practice standardization and, as we did in the natural gas industry, we believe it is best if industry participants develop these types of highly detailed and technical standards. Thus, we are proposing a process, similar to that used in the natural gas industry, that could be used for standardization of business practices, data sets and communication protocols that includes representation of all affected market participants. Upon its formation, the Wholesale Electric Quadrant of the North American Energy Standards Board (NAESB), working closely with Independent Transmission Providers who would collectively serve in an advisory capacity to the board, would produce business practice and electronic communication standards. NAESB would notify the Commission when it has adopted standards, and the Commission would then use rulemaking proceedings to propose the incorporation of these standards by reference into the Commission's regulations. If the industry is unable to reach consensus on a particular standard, the Commission would be available to resolve the dispute, so that the industry process can continue, or the Commission could develop its own standards if necessary. Consistent with gas industry regulation, issues of policy that affect significant resources or that may cause cost-shifting would be resolved at the Commission rather than through the standard setting body.

A. The Interim Tariff

117. Standard Market Design is intended to cure undue discrimination, in part, with respect to the use of the transmission grid. As we discussed in Section III.B.2, there are different rules for bundled retail transmission service and for wholesale and unbundled retail transmission services. These differences result in unduly discriminatory preferences for the vertically integrated transmission owner's bundled retail customers.

1. Placing Bundled Retail Customers under the Interim Tariff

118. We propose that to eliminate this undue discrimination, the transmission component of bundled retail service must be taken under an open access transmission tariff. Under the current pro forma tariff, a vertically integrated utility is required to designate the resources it uses to serve bundled retail customers in the same manner as wholesale customers are required to designate network resources under the Network Integration Transmission Service. We propose to use these designations of network resources in converting service used to meet retail obligations. The existing level of service would be provided pursuant to the new Network Access Service. The load-serving entity or the retail customer would receive either Congestion Revenue Rights or the auction revenues for these rights for the currently designated resources. In Section V of this Notice of Proposed Rulemaking, the Commission sets forth a proposed time-line and implementation process for this conversion process.

119. In the interim, however, we propose to require that bundled retail load be placed under the existing pro forma tariff. While many of the revisions required by Standard Market Design are dependent on the production and adoption of software to determine

locational marginal prices and to operate markets, placing bundled retail load under the existing pro forma tariff can be done immediately. This will remove certain discriminatory practices and is the first step towards placing all transmission service under one tariff. This will require several revisions to the existing pro forma tariff to modify provisions that define the different treatment granted to the service of bundled retail load. Among the revisions that the Commission proposes to require public utilities to file are revisions to Sections 1.19, 13.5, 13.6, 14.2, 22.1(a), 22.1(a), 28.2, 28.3, 33.2, 33.3, 33.3 and 33.5. The specific changes are identified in Appendix A.

120. We propose that the public utilities file these revisions to their tariffs and execute service agreements to take Network Integration Transmission Service on behalf of their bundled retail load no later than July 31, 2003. We recognize, however, that some public utilities (e.g., ISOs) may already be serving bundled retail load under the pro forma tariff. Accordingly, to the extent that a public utility can demonstrate that it complies with this requirement, it may so indicate in its compliance filing.

2. Additional Interim Revisions to the Pro Forma Tariff

121. Since the implementation of the existing pro forma tariff, the Commission has offered clarifications to various provisions of the tariff. Perhaps the most important of these dealt with a customer's right to roll over its existing contract for long-term firm service (Section 2, Initial Allocation and Renewal Procedures).

122. In several orders, the Commission clarified three significant points: (1) a customer must submit a request to roll over its contract no later than sixty days prior to the date the

current service agreement expires;⁷⁸ (2) the public utility may only deny a customer its right to roll over a contract due to future load growth if the public utility includes in the original service agreement a specific, reasonably forecasted need for the transfer capability to serve load growth for network customers at the end of the term of the service agreement;⁷⁹ and (3) a long-term firm customer that requests to use alternate point(s) of receipt or delivery retains its right of first refusal for service at the original point(s) of receipt and delivery at the time the current service agreement expires.⁸⁰

123. These revisions have a significant impact on the rights of current transmission customers and will continue to do so up until the time the SMD Tariff, including auctions of Congestion Revenue Rights, is in place.⁸¹ We propose to require public utilities to make the tariff changes to Section 2.2 of the existing pro forma tariff, as outlined in Appendix A.

B. Independent Transmission and Markets

⁷⁸Entergy Power Marketing Corporation v. Southwest Power Pool, 91 FERC ¶ 61,276 (2000).

⁷⁹Order No. 888-A, as clarified by Public Service Company of New Mexico, 85 FERC at 62,006 (1998); Public Service Company of New Mexico v. Arizona Public Service Company, 99 FERC ¶ 61,162 (2002); Exelon Generation Company, LLC v. Southwest Power Pool, 99 FERC ¶ 61,235 (2002).

⁸⁰Commonwealth Edison Company, 95 FERC ¶ 61,027 (2000).

⁸¹The protections offered by rollover rights are of value in a first-come, first-served priority system, and are valuable for a direct allocation of Congestion Revenue Rights. Once Congestion Revenue Rights are fully auctioned, and access to transmission service will be based on a willingness to pay congestion costs (and losses), it may no longer be necessary.

124. Another form of undue discrimination is the lack of independence of the transmission provider in many regions of the country. As discussed in Section III.B.1, remaining corporate ties between generation and transmission within public utilities are problematic since they allow the vertically integrated utility to exercise market power to advantage its affiliated generation.

1. Independent Transmission Providers

125. To remedy this undue discrimination, transmission service must be provided by an independent entity. Therefore, we propose to require all public utilities that own, control or operate facilities used for the transmission of electric energy in interstate commerce to: (1) meet the definition of Independent Transmission Provider, (2) turn over the operation of its transmission facilities to an RTO that meets the definition of Independent Transmission Provider, or (3) contract with an entity that meets the definition of Independent Transmission Provider to operate its transmission facilities.

126. An Independent Transmission Provider is any public utility that owns, controls or operates facilities used for the transmission of electric energy in interstate commerce, that administers the day-ahead and real-time energy and ancillary services markets in connection with its provision of transmission services pursuant to the SMD Tariff, and that is independent (i.e., has no financial interest, either directly or through an affiliate, in any market participant in the region in which it provides transmission services or in neighboring regions).

127. We propose that affected public utilities must inform the Commission which Independent Transmission Provider will operate the public utility's transmission facilities no later than July 31, 2003. However, a public utility that is a member of an approved RTO or ISO or other entity that meets the definition of Independent Transmission Provider may file a request for a waiver of the filing requirements of this paragraph on the ground that it has already complied with the requirement.

128. Any entity meeting the definition of Independent Transmission Provider would file the SMD Tariff to provide transmission services, including ancillary services, and to administer the day-ahead and real-time energy and ancillary services markets. As discussed further below, an Independent Transmission Provider would also perform market monitoring and market power mitigation, long-term resource adequacy and transmission planning and expansion on a regional basis.

129. An Independent Transmission Provider would also file under section 205 any changes to transmission rates necessary to implement Standard Market Design, no later than 60 days prior to the date on which it proposes to implement Standard Market Design.

130. In addition, one or more public utilities may jointly file an application to meet the requirements of Standard Market Design. Also, an Independent Transmission Provider may make necessary filings on behalf of public utilities required to meet the requirements of this paragraph.

131. We seek comment on whether this remedy is adequate to remove the potential for unduly discriminatory behavior on the part of a vertically integrated transmission

provider. Can the requirements of Standard Market Design be satisfied either by performing the function through an RTO or contracting with an independent entity to perform them? Given that most transmission providers have filed proposals to join an RTO, is a non-RTO compliance option necessary to cure undue discrimination and produce just and reasonable rates for transmission service and the sale of electric energy?

2. Role of Independent Transmission Companies in Standard Market Design

132. We have long recognized that the Independent Transmission Company (ITC) business model can bring significant benefits to the industry. Their for-profit nature with a focus on the transmission business is ideally suited to bring about: (1) improved asset management including increased investment; (2) improved access to capital markets given a more focused business model than that of vertically integrated utilities; (3) development of innovative services; and (4) additional independence from market participants. We believe that these characteristics of ITCs can have significant benefits for the implementation of Standard Market Design, particularly in the areas of development of transmission infrastructure and structural independence from market participants.

133. The Commission recently approved a proposal by several transmission owners to form an ITC, TRANSLink Transmission Company, LLC (TRANSLink), to share responsibility with the Midwest ISO Regional Transmission Organization (the Midwest

ISO)⁸² and other regions for the RTO functions prescribed in Order No. 2000. In that proceeding, the Commission approved a hybrid RTO formation under which specific RTO functions were delegated to either the RTO or the ITC. Regarding the delegation of functions we stated:

Our rulings on the allocation of functions issues are based on our belief that for effective RTO operations, regional trading, and one-stop shopping, a single transmission provider must have overall authority and ultimate responsibility for transmission service in the region. We further believe that the security-constrained, economic dispatch needed for an efficient and reliable market is best operated by an independent regional transmission provider. However, we believe that it is acceptable for some functions with predominantly local characteristics to be delegated to an ITC so long as the RTO has oversight authority in the event that local actions have a regional impact. We find that this is critical to successful RTO development and especially important given the characteristics of the interstate transmission grid. It has become increasingly evident in recent years that even seemingly local issues, such as generator location or isolated transmission bottlenecks, can and do impact the larger grid, and that is why we believe that centralized RTO oversight is needed.

We also remain concerned that vesting control into sub-regional entities may create seams which could easily lead to re-balkanization. These difficult delegation decisions are made with our firm belief that ITCs can flourish under the RTO umbrella and that in performing certain delegated functions, ITCs will be able to effectively manage their assets, protect their value, and bring their expertise to increase efficiencies and enhance the value of their business. Nevertheless, these delegation decisions should not prevent ITCs from seeking additional authority, subject to Commission approval, at a later date after ITCs have gained

⁸²TRANSLink Transmission Company, L.L.C., et al., 99 FERC ¶ 61,106 (2002).

experience under RTO operations.⁸³ We are also guided by the premise that any delegation of functions to an ITC must be consistent with and further the Commission's goals in the SMD Proceeding. We assume in this order that the Midwest ISO will be the transmission provider in the TRANSLink area and will operate a real-time and day-ahead market, or any functions that are required under the SMD final rule.⁸⁴

134. We seek comment on the functions that an ITC should perform under Standard Market Design. Should the Commission retain the same delegation of functions that was approved in TRANSLink? Are there elements of the proposed Standard Market Design that would justify a different delegation of functions? Should an ITC qualify as an Independent Transmission Provider?

135. We seek comment on whether an ITC that has no ties to a Market Participant, as defined in this proposal, is sufficiently independent to act as the Independent Transmission Provider. The ITC may hold grid assets such as transmission facilities and Congestion Revenue Rights and may be allowed a performance-based ratemaking program. Thus the Commission is concerned that the ITC may unduly discriminate in favor of its own transmission interests when carrying out operational and planning decisions in its role as Independent Transmission Provider. We seek comment on

⁸³We recognize that as the Midwest ISO and ITCs gain experience, they should, from time to time, reassess the assignment of the functions and reevaluate whether some that have been delegated to a local level need to be performed at a regional level and vice versa. Likewise, after SMD is implemented, the assignment of functions may need to be reassessed. (Footnote 37 in original).

⁸⁴TRANSLink, 99 FERC at 61,463.

whether such ITC interests in transmission investment may cause the ITC to unduly discriminate in day ahead or real time markets operations or to discount generation, demand response, and other transmission owners' (e.g., merchant transmission) solutions to grid problems. On the other hand, generation and demand response solutions are likely to have the first opportunity to respond to LMPs if it makes economic sense to do so, given the difficulty in siting transmission. Given the planning process and stakeholder input, as well as the Commission's authority to set rates, we seek comment on what specific ways an ITC could make such unduly discriminatory decisions? The Commission is convinced that, if its role is appropriately defined, and opportunities for undue discrimination are addressed, the ITC shows great promise to address grid problems through profit driven activities. One such activity could be reducing congestion where an ITC with properly structured performance based rates would have an incentive. What is the appropriate role for the ITC?

C. The New Transmission Service

136. To address the discrimination described in Section III above and in Appendix C, we will require Independent Transmission Providers to provide a nondiscriminatory, standard transmission service to all customers. This new service, Network Access Service, combines features of both the existing open access transmission services – Network Integration Transmission Service and Point-to-Point Transmission Service. The Network Access Service is grounded in the flexibility of network integration transmission service, but adds a measure of reassignability similar to that available under firm Point-to-

Point Transmission Service. Thus, Network Access Service will give all customers the opportunity to have tradable Congestion Revenue Rights⁸⁵ that will expand their transmission options and enhance competition in wholesale electric markets. It also will result in all transmission services being performed under a single set of rules.

137. To complement Network Access Service and implement the Standard Market Design, Independent Transmission Providers will manage congestion using LMP. Management of transmission grid congestion is difficult to do through bilateral transactions alone; thus a spot market is required to manage congestion efficiently. We believe that congestion management, balancing of load and generation in real time, and the provision of ancillary services can be accomplished most reliably and efficiently by a bid-based, security-constrained spot market.

138. In addition to administering a spot market to manage congestion, the Independent Transmission Provider will also use it to handle imbalances and the procurement of ancillary services. The Independent Transmission Provider would operate markets for energy, regulation, operating reserve - spinning and operating reserve - supplemental. These markets would be security-constrained, bid-based markets operated in two time frames: (1) a day ahead of real-time operations, and (2) in real time. Transmission services will be scheduled through the day-ahead and real-time markets. The

⁸⁵ Congestion Revenue Rights entitle the holder to receive specified congestion revenues in the day-ahead market. To the extent that a customer's real-time schedule coincides with its day-ahead schedule and its Congestion Revenue Rights, these rights offer complete protection against uncertain congestion charges.

Independent Transmission Provider would establish schedules for transmission service, and sales and purchases of energy, regulation, and both operating reserves, to ensure the most efficient use of the transmission grid. Although the Independent Transmission Provider will not be required to operate an organized market for either short- or long-term bilateral transactions, its scheduling process must accommodate such bilateral trades.

1. Basic Rights

139. Network Access Service builds upon the existing Order No. 888 Network Integration Transmission Service and will be available to all eligible customers. As with Network Integration Transmission Service, Network Access Service offers flexible use of the transmission grid – it allows the load-serving entity to choose to serve its load with any available resource on the system (or access any interface to import power from a neighboring system), consistent with the Network Resource Interconnection Service discussed in the Generator Interconnection proposed rule.⁸⁶ Network Access Service allows a customer to have the Independent Transmission Provider integrate, dispatch and regulate the customer's current and planned resources to serve its load as is currently done under the pro forma tariff. Customers, including generators and marketers, can also use this service for through-and-out service, to aggregate resources for resale, and to perform hub-to-hub transactions similar to Point-to-Point Transmission Service. In addition,

⁸⁶Standardization of Generator Interconnection Agreements and Procedures, FERC Stats. & Regs. ¶ 32,560. Network Resource Interconnection Service requires that sufficient network upgrades be built so that interconnecting generators can serve load as a Network Resource, as defined by the existing pro forma tariff.

Network Access Service allows the customer (1) to trade (reassign) its Congestion Revenue Rights and (2) to access points, which, under the current pro forma tariff, are secondary points that may be fully subscribed, by paying all applicable congestion charges.

140. Network Access Service is premised on dispatching of the regional transmission grid so that the customers that value transmission service the most will get it. All requested transactions must be physically feasible under a security-constrained dispatch. Where there are transmission constraints, the LMP system we propose will price out all transactions and redispatch available generation as needed to accommodate all requests for service.⁸⁷

141. Network Access Service gives the customer the right to transmit power between any number of combinations of receipt and delivery points. A receipt point is defined here as the location where a transaction originates, and a delivery point is defined as the location where a transaction terminates. Receipt and delivery points include both individual nodes as well as aggregated points, e.g., trading hubs. Thus, a Network Access Service customer could use this service to move power from a generator (receipt point) to a load (delivery point), from a generator (receipt point) to a trading hub (delivery point), from one trading hub to another, or from a trading hub (receipt point) to a load (delivery

⁸⁷In all but limited cases, this should allow the Independent Transmission Provider to satisfy all requests for service by customers willing to pay the applicable congestion charges.

point). A Network Access Service customer would have access to all receipt and delivery points on the system and would be able to substitute receipt points on a daily or hourly basis through the day-ahead and real-time scheduling processes.

142. Any customer using transmission service, whether a load-serving entity, generator, or marketer, would take Network Access Service. However, as explained more fully in Section IV.D.1, only those customers taking power off of the grid would pay the access charge. (All customers would pay congestion costs and losses associated with their particular transaction.) We expect that, in most instances, it would be a load-serving entity, rather than a generator or marketer, that would be the customer for transactions that result in power leaving the grid, and thus, the load-serving entity would be the entity paying the access charge.⁸⁸

2. Access to Transmission Service

143. Under the existing pro forma tariff, "firm" transmission service implies certainty both with respect to delivery and price. Once a customer taking firm service under the existing pro forma tariff agrees to pay the transmission rate and schedules service, it has full assurance that it will be able to transmit power between its chosen receipt and delivery points without service interruption (absent force majeure or curtailment) and without being subject to any additional costs (e.g., redispatch). However, there are times when a transmission provider cannot offer a guarantee of service availability (absent the

⁸⁸An end-use customer in a state with retail access could be the entity taking transmission service and paying the access charge.

long-term solution of a customer agreeing to pay for system expansion). At these times, under the existing pro forma tariff, only non-firm transmission service (which can be interrupted for economic reasons)⁸⁹ is available at the stated maximum rate. Thus, the existing pro forma transmission service begins with the basic premise of price certainty, but includes a measure of uncertainty regarding service availability that is resolved only if firm service can be secured. In sum, the customer is generally assured of the rate it will pay for transmission service, but, unless it has secured firm transmission service between the specified points, is not necessarily assured that it will receive transmission service.

144. With Network Access Service, all customers who want physically feasible service will be able to receive service; however, uncertainty can arise as to the rate paid to receive the service. In addition to the access charge (which recovers the embedded costs of the transmission system), the customer would be subject to the cost of congestion between its chosen receipt and delivery points. To achieve certainty with respect to price and avoid congestion costs, the customer would have to acquire the Congestion Revenue Rights associated with its specific receipt point-delivery point combination(s).⁹⁰ Thus, Network Access Service, coupled with Congestion Revenue Rights for the desired points,

⁸⁹All services, including firm service, can be curtailed for reliability reasons.

⁹⁰Congestion Revenue Rights provide the rights holder with the revenues associated with congestion between the associated points; thus, any congestion costs it pays are fully offset by these revenues. To the extent the Congestion Revenue Rights holder opts not to schedule transmission service at those points, it would still receive the congestion revenues.

provides the customer with certainty with respect to delivery and price, comparable to the existing pro forma tariff's firm service.

145. Accordingly, customers desiring service comparable to (but actually more dependable than) existing firm transmission service would need to acquire Congestion Revenue Rights for their receipt and delivery points and schedule service between those points in the day-ahead market. With the allocation process we propose in Section IV.H.2, customers under existing contracts will receive Congestion Revenue Rights that match their current use of the system, which will ease and simplify the conversion process. Customers using non-firm transmission service under the existing pro forma tariff could request service when needed in the day-ahead or real-time markets. To the extent the customer is willing to pay congestion costs and transmission losses, its requested transmission service would be available and provided.⁹¹ A customer also has the option of placing a limit on the amount of congestion charges it is willing to pay – to the extent that amount is exceeded, the customer would not take transmission service for that receipt point-delivery point combination during the requested time period. This means no separate non-firm transmission service option is needed under Network Access Service.

3. Service Limitations in the Existing Pro Forma Tariff

⁹¹As discussed in Section IV.D.3, customers exporting power from or transmitting through one region would not be subject to that region's access charge, but would be liable for the cost of congestion and transmission losses associated with its transaction.

146. The existing pro forma tariff limits how the Network Integration Transmission Service and Point-to-Point Transmission Service can be used. It limits the use of interface capability by Network Integration Transmission Service customers to the amount of the customer's load. Under the LMP system that we are proposing, transmission service would be available to any customer up to the full amount of the transfer capability, so long as the customer is willing to pay the applicable congestion charges. The specifics of scheduling power across interfaces is discussed in a later section.

147. The existing pro forma tariff also requires the network customer to take Point-to-Point Transmission Service for any additional third-party sales transaction or to serve load on another transmission provider's system. This will no longer be necessary with Network Access Service, which will be used for all transmission services, including third-party sales transactions and transmission service for load on another transmission provider's system. A customer, however, may prefer to have separate service agreements for service to particular loads for accounting or tracking purposes.

4. Conditions for Receiving Service

148. To receive Network Access Service, a customer must meet the same requirements as those under the existing pro forma tariff for acquiring the right to schedule transmission service: all customers must meet creditworthiness and other eligibility standards, complete an application for service, and meet certain operating standards (e.g., reliability maintenance of customer-owned facilities for integration with the transmission

provider's system, including metering and communications equipment) as defined in the current pro forma tariff. Similarly, the customer must have a service agreement to take service under the tariff. A load-serving entity would also need a network operating agreement, which would detail how the Independent Transmission Provider's system under the SMD Tariff and the load-serving entity's system would work together (similar to a generator interconnection agreement).⁹² These standards are largely unchanged from the existing pro forma tariff. In addition, the customer must agree to pay any congestion charges and transmission losses associated with its request⁹³ and any customer serving load located within the Independent Transmission Provider's system must agree to pay the applicable access charge.

5. Scheduling Transmission Service and Acquiring Congestion Revenue Rights

149. As noted above, a customer would acquire Congestion Revenue Rights to assure price and delivery certainty for its transactions. Anyone can hold Congestion Revenue Rights. Congestion Revenue Rights can be acquired through a variety of means, including: (1) direct allocation that is based on some measure of current or historical

⁹²Consistent with the existing pro forma tariff, a Network Access Service customer would retain the right to request that the Independent Transmission Provider file an unexecuted transmission agreement or network operating agreement if the two parties cannot agree on the terms and conditions of service.

⁹³As noted earlier and more fully explained in Section IV.E.3, a customer can protect itself against the costs of congestion by acquiring Congestion Revenue Rights in the amount of its load and between the receipt/delivery points where its desired resources and loads are located.

rights to the system; (2) periodic auctions; or (3) some combination of these methods.

The initial process for acquiring these rights is discussed in Section IV.H.2.

150. Transmission service will be scheduled through the day-ahead market with deviations accounted for in the real-time market, as discussed in later sections. These scheduling opportunities are comparable to the existing pro forma tariff's requirements (e.g., firm point-to-point transmission service scheduled by no later than 10 a.m. the day before, with schedules submitted after that time accommodated, if practicable, and allowance to make changes to that "day-ahead" schedule prior to the start of the next clock hour). However, the new service synchronizes the scheduling of transmission service and energy, and relies on a transmission customer holding Congestion Revenue Rights or its willingness to pay the cost of congestion, rather than on a firm/non-firm, first-come, first served method, to ration capacity.

151. A Network Access Service customer would have to indicate the location of its receipt and delivery points when it schedules service in the day-ahead or real-time markets.⁹⁴ If a customer holds Congestion Revenue Rights between a set of receipt and delivery points in the day-ahead market, but later decides to take transmission service between a different set of points, the customer would no longer have full protection

⁹⁴Further, consistent with the existing pro forma tariff and the Commission's decision regarding "tagging," the customer must identify the ultimate source and sink so that the various system operators in an interconnection can assess the simultaneous feasibility of all scheduled power flows. See Coalition Against Private Tariffs, 83 FERC ¶ 61,015 at 61,040, reh'g denied, 84 FERC ¶ 61,050 (1998).

against congestion costs for its transaction in the day-ahead market and could incur different congestion costs than the congestion revenues associated with the Congestion Revenue Rights it holds. Similarly, to the extent that a customer's real-time transactions differ from its day-ahead schedule, the customer would be liable for any redispatch costs that occur in real time that are necessary to accommodate its real-time transactions.

6. Designating Resources and Loads

152. The existing pro forma tariff allows a Network Integration Transmission Service customer to designate resources that the customer owns or has committed to purchase pursuant to an executed, non-interruptible contract. The transmission provider must then plan and operate its system to be able to provide firm transmission service from these resources to the customer's load. Under the proposed Standard Market Design, the reservation of capacity for service is no longer required, since a transmission customer pays the congestion cost for transmission service. Thus, there is no longer a need for a Network Access Service customer to designate network resources to get transmission service. While the integration of resources and loads (including behind-the-meter generation) that occurs under Network Integration Transmission Service will continue, a Network Access Service customer will now request receipt and delivery points through the day-ahead scheduling process and real-time transactions.

153. Thus, we believe that the requirement to designate network resources to receive transmission service may no longer be needed. Further, we note that under the existing pro forma tariff the designation of network resources was used in addressing long-term

resource adequacy concerns and in the planning process undertaken to ensure that the resources could be integrated. Because we are now proposing a resource adequacy requirement and a regional planning process to meet these requirements, the requirement to designate network resources may no longer be needed. (See Section IV.J). We request comment on whether designating network resources and loads is necessary for Network Access Service, particularly with respect to performing the integration of resources and loads.⁹⁵ Similarly, with respect to the information required to complete an application for service (Section 2 of the SMD Tariff), is it necessary for the Independent Transmission Provider to request information beyond the identity of and contact information for the customer, service term and commencement date, and receipt and delivery points for the requested service? Does the Independent Transmission Provider need to collect for each service request (but not for each transaction) the location and characteristics of the generation serving the load, detailed descriptions of the load and the customer's transmission system and owned generation?⁹⁶ In sum, do we need separate procedures for service to customers such as marketers, who do not serve load or own generation, or transmission systems and load-serving entities that have all these things? Does the

⁹⁵The relevant sections of the SMD Tariff are Sections B.3 and B.4. While we believe that they may no longer be necessary, they remain in the tariff for ease of reference during the proposed rulemaking process. In the Final Rule, the Commission will determine if these or similar provisions need to be included in the SMD Tariff.

⁹⁶See Sections B.2.2.1(iv) and (v), and Sections B.2.2.2(iii) through (vi) of the SMD Tariff.

integration aspect of Network Access Service require different information to be provided to the Independent Transmission Provider in order to initiate service? Should this information be provided through other means, and what would that be?

7. Substituting Receipt and Delivery Points

154. Under the existing pro forma tariff, choosing alternate resources to meet load required, in effect, placing a request in the queue for new service. If firm capacity were available, the customer would be permitted to use alternate points of receipt (or delivery) on a firm basis. If firm capacity were not available, the customer could choose the point(s) on a secondary, or non-firm, basis.

155. With Network Access Service, this process is no longer necessary. A Network Access Service customer can essentially access any point simply by requesting it through the day-ahead scheduling process or real-time transactions (and be willing to pay congestion costs and losses). To the extent the customer wanted to avoid the cost of congestion for the transaction, it could retain its existing Congestion Revenue Rights and acquire additional Congestion Revenue Rights for its new receipt and delivery points through an auction or secondary market.

156. Alternatively, the customer could request a "reconfiguration" of the Congestion Revenue Rights it holds, i.e., the customer could turn in the Congestion Revenue Rights for the old receipt and/or delivery point and request Congestion Revenue Rights from the new receipt point or to the new delivery point. We seek comment on the MW quantity of reconfigured Congestion Revenue Rights that the customer should be entitled to receive.

There are at least three options. One option is to allocate to the customer the MW quantity that is available specifically as a result of turning in the old Congestion Revenue Rights. Under this option, the customer would receive rights that become available by turning in the old Congestion Revenue Rights. In such a case, the MW quantity of new Congestion Revenue Rights might be different (either larger or smaller) than the MW quantity of the old Congestion Revenue Rights.⁹⁷ A second option is to allocate any MW quantity of new Congestion Revenue Rights that are physically feasible (i.e., it does not adversely affect the Congestion Revenue Rights held by any other customer), including Congestion Revenue Rights that were available before turning in the old Congestion Revenue Rights. The MW quantity of new Congestion Revenue Rights under this option could also be different (either larger or smaller) than the MW quantity of older Congestion Revenue Rights. A third option is to allocate a MW quantity of new Congestion Revenue Rights that is either equal to the MW quantity of the old Congestion

⁹⁷For example, a customer holding a 10 MW Congestion Revenue Right from A to B may want to exchange its existing rights for Congestion Revenue Rights from C to D. Suppose that both the A-to-B and C-to-D Congestion Revenue Rights relied on a common congested flowgate, so that the amount of A-to-B Congestion Revenue Rights and C-to-D Congestion Revenue Rights is limited by the capacity of the flowgate. However, suppose that the A-to-B Congestion Revenue Right relies more heavily on the congested flowgate than the C-to-D Congestion Revenue Right. That is, the proportion of the power flow (known as the “power flow distribution factor”) over the flowgate in transmission service from A to B is greater than the proportion in transmission service from C to D. Thus, giving up 10 MW of A-to-B Congestion Revenue Rights may create the ability to award more than 10 MW of Congestion Revenue Rights (e.g., 15 MW) from C to D. Conversely, a customer with 15 MW of C-to-D Congestion Revenue Rights could exchange them for only 10 MW of A-to-B Congestion Revenue Rights.

Revenue Rights, or, if that is not physically feasible, the largest MW quantity that is physically feasible. Under this third option, the MW quantity of new Congestion Revenue Rights could never exceed the MW quantity of the old Congestion Revenue Rights. The process for acquiring and reconfiguring Congestion Revenue Rights is further described in Section IV.E.3.

8. System Impact and Facilities Studies

157. Most service requests will be resolved through the day-ahead security-constrained dispatch. Nevertheless, the Independent Transmission Provider will need to conduct system impact and/or facilities studies for service involving the interconnection of a new load or generator. The Independent Transmission Provider will also routinely perform simultaneous feasibility studies to determine the configurations of Congestion Revenue Rights that can be accommodated. Thus, except for adding references to the simultaneous feasibility studies that will be performed in response to requests for Congestion Revenue Rights, sections of the existing pro forma tariff addressing various studies will remain largely unchanged. However, as discussed in Section IV.C.8, these studies are now required to be performed by an Independent Transmission Provider.

9. Load Shedding and Curtailments

158. Under the existing pro forma tariff, load shedding and curtailment procedures were developed for inclusion in individual network operating agreements. These procedures should be uniform and, therefore, will be included in the SMD Tariff. In addition, we expect that the majority of constraints will be resolved through the LMP-based congestion

management system, with only localized emergency/reliability contingencies (transmission line outage into a load pocket) needing to be addressed through load shedding or curtailment procedures.

159. This is a major improvement over the current tariff, as it should eliminate most or all TLRs. To the extent practicable, when system conditions require curtailment (in real time) that cannot be resolved through the congestion management system, the Independent Transmission Provider should curtail the customers whose transactions contribute to the constraint on a pro rata basis.⁹⁸ In addition, we propose that to the extent the Independent Transmission Provider is unable to schedule all requests for service made through the day-ahead scheduling process, those customers with Congestion Revenue Rights for their requested receipt point-delivery point combinations should be scheduled first. We seek comment as to whether this scheduling priority is appropriate. While it would grant Congestion Revenue Rights holders an additional measure of certainty of delivery, would this undermine the benefits of having a single transmission service for all customers?

⁹⁸Because we are now proposing to exercise our jurisdiction over the transmission component of bundled retail transactions and to provide a single set of rules and regulations that apply to all transmission service, the limitation imposed by the United States Court of Appeals for the Eighth Circuit on the Commission's curtailment authority over bundled retail customers is no longer relevant. See Northern States Power Company (Minnesota) and Northern States Power Company (Wisconsin), 83 FERC ¶ 61,098, order on clarification, 83 FERC ¶ 61,338, reh'g denied, 84 FERC ¶ 61,128 (1998), Northern States Power Co., et al. v. FERC, 176 F.3d 1090 (8th Cir. 1999), cert. denied, 528 U.S. 1182 (2000), order on remand, 89 FERC ¶ 61,178 (1999).

160. We propose that an Independent Transmission Provider can assess a penalty for failure to curtail if a transmission customer fails to curtail after reasonable notice. The proposed penalty is the locational marginal price plus \$1000 per MWh. The Commission has approved a minimum notice period of ten minutes if the curtailment is for reliability purposes.⁹⁹ We request comment on whether the Commission should continue this practice.

161. We also note that the Commission required transmission providers to incorporate procedures for addressing curtailment of parallel flows involving more than one transmission system (i.e., the Transmission Loading Relief Procedure developed by NERC) as a single generic amendment to the pro forma tariff.¹⁰⁰ Under Network Access Service, procedures for addressing non-discriminatory curtailment of parallel flows will continue to be needed under emergency conditions when the use of a regional congestion management procedure set out in this proposed rule does not completely relieve a constraint.¹⁰¹ Language has been added to Section 9.3, Curtailments of Scheduled Deliveries, to reflect this change.

10. Trading (Reassigning) Congestion Revenue Rights

⁹⁹See Allegheny Power System, Inc., 80 FERC ¶ 61,143 at 61,546 (1997), order on reh'g, 85 FERC ¶ 61,235 (1998)..

¹⁰⁰See North American Electric Reliability Council, 87 FERC ¶ 61,160 (1999).

¹⁰¹Such procedures may need to be refined in light of Standard Market Design.

162. Network Access Service adds the tradability that currently exists for "firm" Point-to-Point Transmission Service, but was not available under Network Integration Transmission Service. Customers may be able to acquire Congestion Revenue Rights from a particular receipt point to a particular delivery point directly from the Independent Transmission Provider, through a formal auction, or through secondary markets. Once a customer has these point-specific Congestion Revenue Rights, the customer may sell them at any time to another entity, whether or not that entity intends to transmit power. The sale could be for all or a portion of the amount or duration of the Congestion Revenue Rights. All resales of Congestion Revenue Rights must be reported on and conducted through the OASIS. As is currently the case in some ISOs, Congestion Revenue Rights will be traded at the price at which purchasers value the rights. The procedures for the auctions and resale of Congestion Revenue Rights are discussed in Section IV.E.3.

163. Revenue Rights must be sold through the OASIS, or whether some bilateral sales may be made and only reported through OASIS after the sale.

11. Ancillary Services

164. The ancillary services provided as part of the current pro forma tariff will largely remain the same under Network Access Service. However, certain ancillary services will be provided through organized markets with appropriate market power mitigation, as discussed infra. The ancillary services markets are discussed in Sections IV.F.1.d and IV.F.3.b.

D. Transmission Pricing

165. The Commission seeks to ensure transmission owners the opportunity to recover their revenue requirements for their transmission systems under Network Access Service. This charge could either be a license plate rate (charge depends on zone of delivery) or a postage stamp rate (same rate applies for all load within the Independent Transmission Provider's service area) and would be paid by all entities serving load within the Independent Transmission Provider's service area. Moreover, to facilitate trading across regions, we are proposing to change our policy on pricing of transactions that start and end in different transmission systems.

166. In addition, we are proposing to refine our policy on pricing of transmission expansions to provide incentives for market-driven solutions. To facilitate the addition of much needed transmission infrastructure, we propose a regional approach to transmission expansion which includes extensive participation by Regional State Advisory Committees¹⁰² to identify the beneficiaries of a proposed expansion and how costs for that expansion should be recovered.

1. Recovery of Embedded Costs

167. Under the existing pro forma tariff, there are two types of transmission services – Network Integration Transmission Service, which is designed for the integration of

¹⁰²Regional State Advisory Committee as discussed more fully in Section IV.K.

resources and loads, and Point-to-Point Transmission Service, which is generally used to export power from one transmission system to another (through-and-out service).

168. To recover the embedded costs of the transmission grid, the Commission has historically permitted transmission providers to assess an access charge, in the form of a load ratio share charge or a per kW per month charge, on all transactions taking place on the transmission provider's system.¹⁰³ For a single transmission utility, these charges usually take the form of a "postage stamp" rate (i.e., the same charge for all customers' use of the utility's grid) and, for an ISO or RTO, a "license plate" rate (i.e., a different charge for the use of the entire regional transmission system that is based on the revenue requirement of the transmission owner's facilities, or "zone," where the transaction sinks).¹⁰⁴ The access charge is assessed on all transactions making use of the transmission provider's system, including transactions where the generator and load are located within the transmission provider's system and where either the generator or the load (or both) are located outside of the transmission provider's system.

¹⁰³ A Network Integration Transmission Service customer pays a monthly demand charge based on its load ratio share of the transmission provider's monthly transmission revenue requirement. The customer's load ratio share is based on the customer's hourly load coincident with the transmission provider's monthly transmission system peak. The firm Point-to-Point transmission customer pays a monthly demand charge for each unit of capacity that it has reserved.

¹⁰⁴ Both PJM and New York ISO use a license plate rate design. PJM and New York ISO have different rate designs for exports and wheel-through services. PJM uses a weighted average of the charges of all transmission for these types of transactions. New York ISO uses the transmission charge of the owner of the intertie that serves as the point of delivery to the adjacent system.

169. While this method of pricing has been effective in recovering a transmission provider's revenue requirement, some changes are required to reflect the new Network Access Service and to address unintended consequences of the current rate design. First, we propose that transmission owners recover embedded costs through an access charge assessed mainly to load-serving entities, based on their respective shares of the system's peak load, i.e., their load ratio shares. Our goal is to minimize the distorting effects that an access charge can have on economic choices. We propose to assess access charges primarily on loads, but not on generators, because the economic choices of loads (such as where to locate) are less likely to be affected by access charges than are the choices of generators.¹⁰⁵ Moreover, even if access charges were imposed on generators or other market participants, it is likely that they would pass along most or all of their access charges to their customers, so that loads would ultimately bear most or all of the transmission fixed costs.

170. Second, we propose to eliminate all "rate pancaking," which involves charging separate embedded cost charges for moving power over separate Independent Transmission Provider service areas. We propose to eliminate rate pancaking both within an Independent Transmission Provider's service area and between service areas. Rate pancaking impedes the ability of distant generators to compete with nearby generators by imposing charges to transmit energy from distant generators that are unrelated to actual

¹⁰⁵Point-to-Point customers wanting to receive a direct allocation of Congestion Revenue Rights would also pay the access charge, as discussed below.

variable transmission costs. Assessing the access charge primarily to load-serving entities based on their load ratio share rather than on the number of service areas over which energy is transmitted increases generation competition by allowing distant generators to compete more easily with nearby generators.

171. As discussed further below, we propose that customers paying access charges would receive Congestion Revenue Rights (or alternatively, revenues from the auction of Congestion Revenue Rights). Thus, in exchange for paying the fixed costs of the transmission system, those paying access charges would receive the financial benefits – the stream of congestion revenues – resulting from usage of the transmission system. In addition, we seek to minimize cost shifts that could result from our proposal, and we propose to maintain as much as possible the explicit and implicit transmission rights currently held by customers. Thus, customers currently receiving Network Integration Transmission Service and firm Point-to-Point Transmission Service under the existing pro forma tariff would receive Congestion Revenue Rights based on their existing service levels. However, there are two issues regarding access charges and the allocation of Congestion Revenue Rights on which we specifically seek comment.

172. First, we seek comment on the treatment of existing customers taking long-term firm Point-to-Point Transmission Service that are not load-serving entities. Such customers currently pay an embedded cost charge in order to receive firm Point-to-Point Transmission Service under the Order No. 888 pro forma tariff. We believe that it would be inequitable for customers to receive an initial allocation of Congestion Revenue Rights

unless they also pay a share of transmission embedded costs. We also believe that it would be inequitable for customers to pay a share of transmission embedded costs without receiving an initial allocation of Congestion Revenue Rights. Thus, we seek comment on two options. One option is for these customers to continue paying their embedded cost charges in exchange for receiving Congestion Revenue Rights that reflect their current levels of Point-to-Point Transmission Service. This option would help minimize cost shifts, while maintaining the transmission rights currently held by these customers. On the other hand, this option would recover a portion of embedded transmission costs from customers that are not loads. The second option is to eliminate the access charges for these customers while also allocating no Congestion Revenue Rights to them. This option avoids recovering embedded costs from entities that are not loads. However, it would result in some shifting of the responsibility for recovering embedded costs, and it would fail to maintain the transmission rights currently held by these customers. We seek comment on the merits of these two options, as well as whether the Final Rule should select one option or, alternatively, allow customers to choose between them.¹⁰⁶

¹⁰⁶We propose that Congestion Revenue Rights be directly assigned only to long-term firm customers, consistent with the existing pro forma tariff's right of first refusal. Thus, short-term and non-firm point-to-point customers would not receive Congestion Revenue Rights under direct assignment. These customers, therefore, may wish to structure their contracts such that they expire at the time Standard Market Design is implemented. This way, while they would not receive Congestion Revenue Rights, they also would no longer be paying an access charge.

173. The second issue concerns the treatment of load-serving entities in retail open access states that attract loads away from their traditional utility suppliers. Under our proposal, a new load-serving entity that attracts load from other suppliers would be assigned a share of embedded costs – costs previously assigned to other suppliers. In areas where there is no Available Transfer Capability for additional Congestion Revenue Rights, we seek comment on how such new load-serving entities should receive an allocation of the customer's former load-serving entity's Congestion Revenue Rights. We propose that Congestion Revenue Rights "follow the load." Thus, Congestion Revenue Rights previously allocated to other suppliers whose loads (and access charges) have been reduced would be reallocated to the new load-serving entities.

174. We propose to permit the use of license plate rates such as those that are currently in effect within ISOs. We seek comment, however, on whether we should retain license plate ratemaking only for a transitional period and at some later date, require that all regions have postage stamp rates. Should the Commission upon the recommendation of a Regional State Advisory Committee accept an embedded cost recovery mechanism for the region which may vary from neighboring regions?

175. To better illustrate the pricing proposals we have included Appendix F which identifies by customer types whether and under what circumstances they will pay the access charge and/or receive Congestion Revenue Rights under Network Access Service.

2. Rates for Bundled Retail Customers

176. When a vertically integrated utility joins a regional organization such as an ISO or RTO, the Commission has required that the utility execute a service agreement under the regional transmission provider's transmission tariff. For instance, the Commission required the vertically integrated utilities in GridSouth to execute a service agreement under the GridSouth transmission tariff, thus ensuring that these utilities would take service for their bundled retail load under the same terms and conditions as all other users of the grid.

177. With respect to whether the GridSouth transmission charge should be applied to the bundled retail load, the Commission permitted the utilities to pay the transmission portion of the bundled retail rate, but required that the service agreement explicitly state the rate to be charged.¹⁰⁷ The Commission added that having vertically integrated utilities pay GridSouth for transmission to serve their bundled retail customers does not make those utilities' retail rates subject to our jurisdiction. Rather, the Commission stated its willingness to accommodate the utilities paying GridSouth a transmission rate equal to the transmission component of their bundled retail rates, as long as the price is clearly stated, reduced to writing in contracts with GridSouth, and is not accomplished by omission.¹⁰⁸

¹⁰⁷Carolina Power & Light Co., et al., 94 FERC ¶ 61,273 at 61,999, order on reh'g, 95 FERC ¶ 61,282 (2001).

¹⁰⁸95 FERC ¶ 61,282 at 61,991.

178. Now that the Commission is asserting jurisdiction over all transmission service in interstate commerce, including that for bundled retail service, the question arises as to whether different charges for transmission service for wholesale and bundled retail customers should be permitted. Allowing different rates for wholesale and bundled retail customers could lead to undue discrimination if the rate setting policies of the state and the Commission differ significantly. The Commission seeks comment on whether all customers should be charged the same transmission rate either upon implementation of Standard Market Design or after a reasonable transition period of four years.

3. Inter-Regional Transfers

179. Under current rate designs, a user that transmits power from one region to another would pay two transmission charges to recover the embedded costs of the transmission provider from which power was exported as well as the embedded costs of the transmission provider where power is delivered to load. As long as transmission owners have an opportunity to recover their embedded costs, to increase competition, we propose to prevent customers from being assessed multiple transmission charges.

180. We have concluded that rate treatment for inter- and intra-regional transactions should be consistent to avoid creating artificial incentives or disincentives for trade across regions. Thus, the design of rates for Network Access Service should eliminate the payment of multiple access charges, such that only one access charge is paid for power to reach load. Accordingly, an export and through-and-out transaction originating in an Independent Transmission Provider's system and terminating at a load in another

Independent Transmission Provider's system would pay only the access charge for the transmission system where power is ultimately delivered to load.¹⁰⁹ This will encourage broader areas of competition by eliminating multiple access charges, and in particular would reduce the harsh inequities of regional boundary definition on those customers near such boundaries.

181. It has become apparent that transmission pricing across RTO borders can have a significant impact both on power purchasing decisions and on RTO formation. A customer's choice as to whether to purchase power from a generator located within the same RTO or a neighboring RTO is directly affected by the fact that one generator faces an additional access charge to reach the RTO in which the load is located. This additional access charge may cause the sale to become uneconomic.¹¹⁰

182. In addition, decisions on which RTO/ISO to join may be affected by inter-regional pricing. Choices driven by the economics of transmission owner's merchant function's trading patterns, rather than by the most rational and efficient aggregation of transmission assets for a particular region, could result in oddly configured RTOs.

¹⁰⁹However, the transaction would still be responsible for applicable congestion charges and transmission losses in the originating and any intermediate transmission systems.

¹¹⁰E.g., a load and Generator 1 with a cost of \$25 are located in RTO A, and a competing Generator 2 with a cost of \$24 is located just across the border in RTO B. On its face (and absent congestion), it appears that the load should choose Generator 2 in RTO B. However, because Generator 2 faces a \$2 transmission charge from RTO B, it is unable to compete with Generator 1 even though it is a more efficient unit simply because of the additional access charge.

183. Rate pancaking across the numerous transmission owning utilities that comprise the RTO has been eliminated by the implementation of license plate rates, while continuing to provide an opportunity for the transmission owners to recover their full revenue requirements. We propose that the same or a similar rate structure should be applied to inter-regional transfers. In a competitive market environment, reliability and the supplier's cost of generation, rather than sunk transmission costs, should be the primary drivers for a customer's choice of power suppliers. To the extent rate design facilitates that result, transmission owners would have a greater incentive to join an RTO based on where their transmission facilities most benefit customers and markets, not on where their generators have better opportunities to make off-system sales (i.e., an access charge for exporting power from one region to a neighboring region should not be the deciding factor).

184. However, absent other adjustment mechanisms, if customers going through and out of an RTO are no longer charged access fees by that RTO for transmission service, these costs would instead be borne by the load served by the RTO through the existing load ratio share methodology.¹¹¹ Under the commonly used license plate rate design, load within a particular RTO zone would pay that transmission owner's full embedded costs, including the portion that is currently contributed by through-and-out customers. This may create problematic cost shifts for certain transmission providers that currently

¹¹¹This would also be true for a non-RTO Independent Transmission Provider.

receive a significant amount of revenue from exports and wheel-throughs (e.g., AEP and Cinergy). While simply eliminating the transmission charge for through-and-out service may avoid the skewing of purchase and sale decisions by inter-regional transaction charges, it will result in cost-shifting and may stifle new transmission investment since state regulators will not generally favor having their customers pay for facilities that may primarily benefit other states.

185. Therefore, we propose to create a mechanism that recognizes the import/export quantities in establishing the revenue requirement to be recovered through the access charge. We seek comment on two approaches that could be used.

186. One method would be to have the "source" Independent Transmission Provider allocate a portion of its revenue requirement to the "sink" Independent Transmission Provider's transmission customers. An Independent Transmission Provider's revenue requirement could be reduced by the amount of revenues associated with through-and-out service and that portion of the revenue requirement would then be included as uplift in the scheduling charge paid by all customers of the sink Independent Transmission Provider in whose service area the power sinks. Under this approach, costs would not be shifted from the beneficiaries of the inter-regional transaction to the load on the source side of the transaction. At the same time, embedded cost recovery would not interfere with short-run efficiency, since embedded costs would not be recovered in individual inter-regional transactions, but would instead be recovered through uplift from all customers in the zone of the sink Independent Transmission Provider. This method would require a projection

of inter-regional transfers and a rate filing to accomplish the re-allocation of costs between Independent Transmission Providers. It would also require a decision as to how narrowly to focus the cost allocation (e.g., RTO to RTO, export zone to import zone).

187. Alternatively, under a revenue crediting approach, inter-regional transfers could be priced at the load ratio share charge (or a similar transmission charge)¹¹² and the inter-regional transaction charges would be netted out over some time period (e.g., one month or one year). This method would assign the inter-regional charges to all customers within the sink Independent Transmission Provider. The cost of transmission on a neighboring Independent Transmission Provider associated with net imported power could be charged to all of the net importing Independent Transmission Provider's customers through the Independent Transmission Provider's scheduling charge. The revenues would be returned to all transmission customers within the net exporting Independent Transmission Provider.

188. We seek comment on whether there should be a uniform cost allocation of inter-regional costs among all zones within an Independent Transmission Provider's system. For instance, there will likely be opposition to a region-wide charge by customers who do not import power. To address this concern, the inter-regional transfers could instead be netted out between zones within neighboring Independent Transmission Providers. This way the costs would be assigned to all customers within the import zone and the revenues

¹¹²An explanation of how this charge may be calculated is contained in Appendix F.

would be returned to the export zone. These transmission costs could be assigned to the zone where the power was imported as if the neighboring Independent Transmission Provider's facilities were part of that zone. Likewise, the zone where exports leave an Independent Transmission Provider would receive the transmission payments associated with the exports. It is possible that the revenue sharing plan used by ISOs with license plate rates to resolve intra-ISO, interzone transactions could be broadened to encompass inter-RTO transactions.

189. As noted above, the proposed rule advocates treating inter- and intra-regional transmission pricing the same. As explained elsewhere, customers within the region who pay the access charge will be entitled to Congestion Revenue Rights or the revenues from the auction of those rights. We propose a similar result for inter-regional transactions when customers in one region are paying a portion of the embedded costs of another region. We seek comment on how to assign Congestion Revenue Rights to the customers of the importing region. For example, if Midwest ISO is a net exporter to PJM, customers on PJM's system will be obligated to pay a portion of Midwest ISO's embedded costs. PJM's customers could receive a proportionate share of Midwest ISO's Congestion Revenue Rights.

4. Application of Inter-Regional Pricing to Parallel Path Flows

190. To the extent the Commission adopts a true-up methodology for recovering the costs of through-and-out services, should a similar pricing methodology be applied to parallel path flows? Parallel path flows are comparable in that one region benefits by the

use of a neighboring region's transmission facilities. Parallel path flows are currently resolved through cooperation. An alternative method would be to price all uses of the grid. We seek comment as to how cost impacts of parallel path flows across regional borders should be addressed.

5. Pricing of New Transmission Capacity

191. The existing transmission grid has fallen far behind the demands that have been placed on it. Over the last ten years, we have seen a strong increase in the amount of new generation, which has been built largely in locations that make the most economic sense for the builder of the generation (i.e., where land is affordable and economic sources of fuel, water and labor are near). However, we have yet to see a parallel jump in construction of transmission infrastructure. The absence of needed new transmission facilities has led to more and more congestion, which hinders customers from seeking and depending on more distant and competitive supply choices.

192. The sluggishness of transmission construction is largely because: (1) siting transmission is a long and contentious process; and (2) mismatches between those who benefit from the new facilities and those who pay for them, particularly when the two affected sets of customers are served by different transmission providers, are often more than enough to make sure the new facilities do not get built. The Department of Energy's 2002 National Transmission Study points to state-by-state siting approval, a lack of

regional institutions and a lack of clarity in regulatory pricing policy as several of the barriers to transmission investment.¹¹³

193. The Commission's pricing policy for network upgrades, whether for reliability or economic reasons, has traditionally favored "rolled in" pricing, where all users pay an administratively determined share of new facilities. This policy was based on the rationale that the transmission grid is a single piece of equipment such that system expansions are used by and benefit all users due to the integrated nature of the grid. This method forms the basis of the pricing proposal in the Generation Interconnection proposed rule.

194. If the expansion is for region-wide reliability, there is little disagreement as to who should pay for the necessary facilities – all ratepayers. Likewise, interconnection facilities are non-controversial; there is general agreement that these facilities should be directly assigned to the interconnecting generator.

195. What we see, however, is that economic expansions that would remove congestion and allow customers to reach more distant power supplies are the most difficult to get sited. This is at least in part because state siting authorities have no interest in siting a line that benefits a particular generator or a distant load in another state because to do so would require the load on the constructing public utility's system to pay for the new facilities. The state authorities, at a minimum, need assurance that the costs of that

¹¹³See DOE National Transmission Grid Study.

expansion will be paid for by those who benefit from the expansion in order to have sufficient incentive to site the new facilities.

196. Our goal is to remove any cost recovery impediments to transmission expansion so that needed upgrades get built now. Traditional means of expansion pricing may not be the most effective way of encouraging new transmission infrastructure, in part perhaps because they do not take into account the wide regional benefits of higher voltage upgrades that can accrue beyond a single transmission owner's system.

197. We believe that a more precise matching of beneficiaries and cost recovery responsibility would encourage greater regional cooperation to get needed facilities sited and built. Our preference is to allow recovery of the costs of expansion through participant funding, *i.e.*, those who benefit from a particular project (such as a generator building to export power or load building to reduce congestion) pay for it.

198. The Generator Interconnection proposed rule introduced the idea that participant funding may be an acceptable pricing policy where an independent entity determines: (1) the cost of and responsibility for needed upgrades; (2) congestion price signals to which the customer responds (along with Congestion Revenue Rights); and (3) the assumptions underlying the power flow analysis.¹¹⁴

199. The Commission envisions that, under Standard Market Design, the Independent Transmission Provider will perform all of these functions, which will allow the

¹¹⁴The Commission is currently reviewing extensive comments on this topic in that proceeding.

Commission to consider the use of participant funding. However, full compliance with Standard Market Design will take some time. We are eager to see new infrastructure in place as soon as possible and believe that participant funding will be a useful tool to make that happen. Accordingly, we propose that, for proposed transmission facilities that are included in a regional planning process which is conducted by an entity, whether an RTO, ISO, or other independent entity, that is independent, we will consider participant funding for that project.

200. In the absence of independence, we would apply a default pricing policy that would recognize the regional benefits of transmission expansions. Under this default policy, we propose to roll-in on a region-wide basis all high voltage network upgrades of 138 kV and above. Since lower voltage, sub-regional transmission needs are less likely to benefit the whole region, the cost of network facilities below 138 kV could be more appropriately allocated to a sub-region (e.g., a single transmission owner or a "license plate" zone) where the expansion facilities will be located. Consistent with our proposal for interregional transmission service pricing, costs would be allocated to the region that benefits from the expansion, which may not be the same as the region in which the expansion facilities are located. This proposal recognizes that high voltage expansions can have benefits beyond the borders of the local transmitting utility and, therefore, assigns a portion of these costs to more distant beneficiaries.

201. Further, as we explain in Section IV.G.3, Regional Planning Process, we encourage the formation of Regional State Advisory Committees, which, in addition to

facilitating the siting of regional expansions, can enable states to work together to identify beneficiaries of expansion projects and make recommendations on pricing proposals. To the extent there is agreement within the Regional State Advisory Committee, the Commission would look favorably on a pricing proposal by the Regional State Advisory Committee if it is consistent with the FPA. Such a proposal might take the form of roll-in, an assignment to beneficiaries, or some combination of the two.

202. We seek comment whether these pricing proposals are appropriate to meet our goal of expediting needed infrastructure investment or whether another method would be more effective.

E. The New Congestion Management System

203. Under Network Access Service, all transmission customers may request transmission service. The Independent Transmission Provider must honor all valid transmission requests where there is sufficient capability, i.e., when there is no transmission congestion. However, when there is transmission congestion we propose to require that all Independent Transmission Providers allocate scarce transmission capability using a price system. Specifically, we propose to require that all Independent Transmission Providers manage congestion using a system of LMP and Congestion Revenue Rights. Under LMP, the price to transmit energy between any receipt point and delivery point reflects the marginal cost (including the marginal opportunity cost) of such transmission service, and the price of energy at each location reflects the marginal cost (as reflected in participants' bids) of producing energy and delivering it to that location.

1. Locational Marginal Pricing

204. LMP is the method that is currently used for managing congestion in the regional markets run by both PJM and New York ISO. It is also proposed to be adopted as the congestion management system for ISO-New England in 2003 and for the California ISO in its proposed market redesign.¹¹⁵ Marginal pricing, a fundamental concept in economics, is the basis for LMP.¹¹⁶ Marginal pricing is the idea that the market price should be the cost of bringing the last unit to market (the one that balances supply and demand). LMP in electricity recognizes that the marginal price may differ at different locations and times. Differences result from transmission congestion which limits the transfer of electricity between the different locations.¹¹⁷ The marginal price of energy at a particular location and time – that is, the energy LMP – is the additional cost of procuring the last unit of energy supply that buyers and sellers at that location willingly

¹¹⁵See California ISO's Comprehensive Market Design Proposal, Docket No. ER02-1656-000 (May 1, 2002); see also California Independent System Operator Corp., 100 FERC ¶ 61,060 (2002).

¹¹⁶It is a widely accepted principle of economics that markets work efficiently when prices reflect marginal costs. See Alfred E. Kahn, The Economics of Regulation: Principles and Institutions, The MIT Press, Cambridge, Massachusetts, reprinted 1988, pp. 63-70. The economic rationale for applying marginal cost pricing to an electricity network using the concepts of LMP was presented in Schweppe, F.C., et al., Spot Pricing of Electricity, 1988, Norwell, MA, Kluwer Academic Publishers; and Hogan, William W., "Contract Networks for Electric Power Transmission," Journal of Regulatory Economics, 1992, vol. 4, pp. 211-242.

¹¹⁷Prices may also vary based on transmission losses. For purposes of simplification this discussion focuses on the differences due to energy prices alone.

agree on to meet the demand for energy. That is, it is the price that "clears the market" for energy.¹¹⁸

205. LMP is a market-based method for congestion management. Congestion is managed through energy prices and transmission usage charges (congestion and loss charges) determined in a bid-based market. When there is no congestion anywhere on the system (when there is enough transmission capacity to get power from the cheapest available generators to all potential buyers) there will be only one energy price in the

¹¹⁸Under LMP, all suppliers selling at a location receive the market clearing price, including those who offer in their bids to sell for less. Similarly, all buyers purchasing at the location pay the market clearing price, including those who offer in their bids to purchase at a higher price. An alternative policy would be to pay each seller its bid price (and perhaps, to charge each buyer its bid price). We propose a single market clearing price for several reasons. First, it encourages sellers to submit bids that reflect their marginal costs (and thus, the sellers selected in the energy auction are more likely to be the sellers with the lowest actual costs). Sellers without market power could not increase the market price by increasing their bids, so bidding above their marginal costs would have no benefit to them. Bidding above marginal cost would merely create the risk that the seller would lose in the auction when the market price was higher than the seller's marginal costs, and thus, the seller could have earned a profit. Moreover, by paying all sellers the market clearing price, sellers with marginal costs below the market clearing price would receive revenues to help recover their fixed costs. A policy of paying each seller its bid would encourage sellers to bid above their marginal costs, since doing so would be the only way for them to earn a profit. As a result, the sellers selected in the auction would not necessarily be the sellers with the lowest actual costs. Moreover, if the pay-as-bid policy were applied only to sellers (and not to buyers), so that buyers were charged the average payment made to sellers, buyers would face a price that was lower than the highest accepted seller's bid. This result would encourage inefficient purchases and poor demand response. For example, on a hot day when the highest accepted seller's bid is \$1000/MWh but the average payment to sellers is \$400/MWh, charging buyers \$400/MWh under pay-as-bid would encourage less demand response than a market clearing price policy of charging \$1000/MWh. If the pay-as-bid policy were applied to both sellers and buyers, then the revenue collected from buyers would usually differ from the revenue paid to sellers.

transmission system, the price bid by the last, or marginal, generator that provides energy or load that offers to reduce its demand.¹¹⁹ When there is congestion, the cheapest generators may be unable to reach all their potential buyers. Consequently, when there is congestion there may be many different energy prices across the transmission system.¹²⁰ Under LMP, the Independent Transmission Provider will establish separate energy prices at each node on the transmission grid and separate prices to transmit energy between any two nodes (receipt and delivery points) on the grid. These prices reflect the cost of congestion. LMP relies on economic redispatch in managing congestion. Redispatching means decreasing the energy the Independent Transmission Provider obtains in front of the constraint (where the power is flowing from) and increasing the energy the Independent Transmission Provider obtains behind the constraint (where the power is flowing to). The cost of redispatch is the basis for the congestion charges under LMP. If a customer is willing to pay the marginal cost of redispatch, which it signals through its bids, the Independent Transmission Provider will schedule the transmission service.

¹¹⁹The operation of the bid-based auction for energy is described further in Section IV.

¹²⁰Because the transmission grid is a network, reducing transmission service between one receipt point - delivery point pair (e.g., from A to B) may free up transmission capability for transmission service between a different receipt point - delivery point pair (e.g., from C to D), albeit not necessarily on a MW-for-MW basis. For example, reducing service from A to B by 2 MW may allow an additional 1 MW of transmission service from C to D. If so, the price to transmit 1 MWh of energy from C to D must reflect at least what a customer denied 2 MW of service from A to B would have been willing to pay.

206. For example, assume there is congestion or a constraint on one transmission interface. Some low-cost generators may not be able to deliver energy to load on the other (import) side of the constraint. So, they will need to reduce their production because of the constraint. To signal these generators to reduce their production, the energy price that these generators would receive would be lowered. To replace the low-cost generation, more expensive generators on the other side of the constraint (export) must be dispatched. To signal to these higher cost generators that they should increase their production, the energy price they would receive would increase. As a result the energy price on each side of the transmission constraint would be different. The energy price would be lower on the side where more suppliers are trying to sell out of the region than can be accommodated by the transmission capacity. The energy price would be higher on the side where more expensive local generation must be used because of the transmission constraint. As discussed further in Section IV.F., for purchasers of energy in the Independent Transmission Provider-run spot markets, the LMP at the node closest to them is their delivered power cost (energy charge plus transmission charge). The generators are then paid the LMP at the nodes closest to them.

207. For customers buying energy through bilateral contracts rather than in spot markets, the transmission usage charge would reflect the marginal cost of transmission between a receipt point and a delivery point.¹²¹ In the above example, the difference

¹²¹Transmission losses will also be recovered through the transmission usage
(continued...)

would be the marginal cost of moving energy from the import to the export side of the constraint which should equal the difference in the energy price on the import and the export side of the constraint. In other words, the transmission usage charge for bilateral transactions would be the difference between the LMP at the receipt point and the delivery point. When congestion exists, the difference in energy prices to transmission users is a price signal that reflects the marginal cost of economic dispatch of resources necessary to accommodate the transmission service. Those who place a higher value on the transmission capacity and the value of the ultimate delivered electricity, will be willing to pay higher transmission usage charges. Also, because transmission usage charges for bilateral transactions are based on the differences in spot market energy prices, the proposed congestion management system would not bias a customer's choice between purchasing energy through the spot market versus a bilateral transaction.

208. LMP uses a financial instrument called a Congestion Revenue Right to provide customers with price certainty for transmission service.¹²² A Congestion Revenue Right is a financial tool that allows a customer to protect itself against the costs of congestion. A Congestion Revenue Right ensures that the holder of that right will be protected against congestion costs for the transmission service covered by that right in the day-ahead

¹²¹(...continued)
charge and included in the energy prices under LMP.

¹²²As discussed above, we also propose that Congestion Revenue Rights would provide a scheduling priority in certain circumstances.

market.¹²³ Once the day-ahead market closes, all customers pay for the service requested and, if they hold Congestion Revenue Rights, are paid congestion costs associated with those rights. Thus, the customer has bought and paid for a quantity of transmission at a specified price.

209. Any changes a customer wants to make to the transmission service it has scheduled in the day-ahead market must be accomplished in the real-time market at real-time prices, which may be different from the day-ahead prices. A customer wanting less transmission service than it requested and received in the day-ahead market would effectively sell back to the market the amount of unused service. Conversely, a customer needing an additional amount of transmission service could buy the additional amount of service in the real-time market. No congestion revenues are paid to Congestion Revenue Rights holders for transactions made in real-time market.¹²⁴

210. The LMP system for congestion management is better suited to manage congestion in a competitive market than the congestion management system under the Order No. 888

¹²³For example, a customer holding Congestion Revenue Rights could be charged the congestion costs (e.g., \$10 MWh) and then receive a credit on the same bill for congestion revenues (e.g., \$10 MWh). So, the net congestion costs paid by the customer is \$0. The customer, however, would have to pay for transmission losses.

¹²⁴For example, a customer schedules and receives 100 MW of transmission service the day ahead at a congestion cost of \$2/MW. The customer pays the \$2/MW of congestion charges to the Congestion Revenue Rights holder (which could be itself). The customer may later decide it only needs 90 MW. It could then sell in the real-time market the unneeded 10 MW. If congestion in the real-time market is \$3, the seller would receive \$3/MW (or \$30) for the sale of the 10 MW of transmission service from the buyer of the transmission service.

pro forma tariff (pro rata curtailment) because LMP allocates scarce transmission capacity to those who value it most and it relies on an incentive system (i.e., it assigns congestion costs to the transactions that cause the congestion) that encourages market participants to buy and sell power in a manner that is consistent with the reliable operation of the system. Under an LMP system, market participants have greater commercial flexibility in arranging transactions. Market participants have the ability to signal whether they are willing to buy their way through transmission constraints. Under the current system they do not have the ability to do that, in part because transmission providers do not have a mechanism for recovering the cost of economic redispatch. Currently, these types of transactions would not be scheduled because of the existence of congestion. Also, Network Access Service customers would have the ability to voluntarily resell their Congestion Revenue Rights when others value them more highly. Because market participants will see and be responsible for the full effect of their decisions on congestion costs, each have an incentive to manage its own transactions in a way that is consistent with a least-cost dispatch consistent with reliable system operations.

211. The proposed SMD Tariff lays out the general framework and the basic rules for LMP. It is based on the best practices we have seen. We recognize that in certain regions there may need to be additional rules or changes to accommodate specific regional requirements. We also recognize that over time there likely will be a need to update the tariff provisions to offer new service options or to further refine the market rules. The pro forma tariff is not intended to be a static document, but rather one that will evolve over

time and meet the needs of the marketplace. We seek comment on how best to recognize this need for regional variation and the need for continued refinement in the rules.

212. One concern that has been expressed in the Standard Market Design conferences and in comments on the Working Paper is that while LMP may work well with systems that are dominated by thermal plants, it may not work in systems that primarily rely on hydroelectric resources. In particular, the Pacific Northwest is concerned that an hourly bid-based system with LMP may be in conflict with Northwest resource uses, practices and obligations, which are dominated by hydroelectric generation. Much of this is from "run-of-river"¹²⁵ facilities that cannot store water, and at which energy is lost if a generator does not run when water is available. Because the decision to run is virtually automatic, many Northwest parties see no need for a bidding system. Also, many of the hydroelectric facilities of the Columbia River System must coordinate their operations; whether a downstream facility runs depends on whether an upstream dam runs and releases water. Some of this coordination is among facilities in the United States and Canada and is subject to international treaties. There is a concern that a bid-based system with LMP, which requires individual generators to bid independently against one another, ignores this cooperation or even would view such cooperation as collusion in a market system. Some coordination agreements assure that low-cost transmission will be made

¹²⁵Run-of-river facilities use the natural flow of the river to generate electricity. They typically divert water from a natural channel, run the water through a turbine to produce energy and then return the water to the natural channel downstream of the turbine.

available to implement the coordination, and there is a concern that LMP congestion pricing may be incompatible with these agreements.

213. Northwest parties note that while annual costs in a thermal system are minimized simply by minimizing the costs in every individual hour the same does not hold true in a hydropower system. A hydroelectric dam with stored water has a marginal running cost close to zero, however, this does not mean that it should be dispatched first every hour. Rather, the value of hydropower over time depends on when that stored energy system can best be released to minimize costs over a season, an year, or even a multi-year period. Thus, there is a concern that in a hydropower system, a congestion management and energy spot market designed to minimize hourly costs will not minimize costs over a longer period.

214. Moreover, commenters have noted that decisions about water use in the Northwest are based on more than electric power cost minimization. Decisions about use of hydropower facilities involve coordinated trade-offs among power needs, the needs of fish and wildlife, irrigation, flood control, recreation and other factors, which may be difficult to reflect in the bids of individual units. Some parties in the Northwest acknowledge that a bid-based LMP system could be adapted to meet the objections above but are concerned either that such a system may be imposed without adaptation or that the adaption will be done poorly. There is also concern that adaptation to a bid-based security-constrained system may reopen such issues as transmission priorities and preference power allocations that have been settled over many years of negotiation based

on factors other than market efficiency. Finally, Northwest parties worry about obtaining sufficient Congestion Revenue Rights to protect against congestion charges.

215. We believe that the proposed Standard Market Design would work well in every region and for all types of fuel sources; we believe that the concerns expressed by participants in the Pacific Northwest can be accommodated within the LMP system we propose. First, use of the Independent Transmission Provider's bid-based spot energy markets would be optional. No one would be required to bid into these markets (except when market power mitigation is imposed).¹²⁶ Hydropower generators could choose to self-schedule without submitting a price bid. As a result, the bilateral contractual energy arrangements of the Northwest would be unaffected. Thus, for example, hydropower facilities along a common waterway that wish to develop a coordinated schedule without submitting energy price bids would be free to do so. Also, hydropower facilities that must consider non-price factors such as the needs for irrigation, flood control, and fish and wildlife in their scheduling decisions could do so through the self-scheduling feature.

216. For hydropower generators that wish to participate in the Independent Transmission Provider's spot energy markets, the Standard Market Design that we propose can accommodate the special features of hydropower facilities. Suppliers would be allowed to reflect their opportunity costs in their bids; bids need not be limited to marginal running costs. Also, generators such as hydropower facilities would have the

¹²⁶The market power mitigation measures would be developed on a regional basis and would take into account the special characteristics of hydropower.

option (but not the requirement) of requesting the Independent Transmission Provider to schedule the generator's designated MWhs over the highest priced hours of the day, to economically optimize hydropower production over the day. LMP is a result of a least-cost dispatch of the resources available to the transmission system in a manner that recognizes both the operational limits of those resources and the operational limitations of the transmission system. As a result, customers' loads can be met at the lowest total cost (as reflected in the submitted bids) consistent with the reliable operation of the system, which should be the objective on any system regardless of the resource base of the transmission system.

217. In short, we see no reason why the proposed Standard Market Design would prevent hydropower generators from operating in a way that accommodates their special features. Indeed, we believe that the LMP system would aid hydropower generators in optimizing the economic value of their resources within their legitimate operational constraints, because the prices for energy and transmission would signal the economic costs of providing energy and transmission service at different locations and time periods.

218. Finally, our proposal here would not abrogate existing pre-Order No. 888 transmission contracts, so customers holding these rights could continue their existing services under the existing contractual provisions. In addition, this proposal would allocate Congestion Revenue Rights or auction revenues to parties based on their recent historical usage of transmission. Thus, customers receiving transmission service under the Order No. 888 pro forma tariff, as well as entities previously serving bundled retail

load outside the pro forma tariff, would receive Congestion Revenue Rights to protect against congestion charges.

219. We agree that the operational limits of both the resources and the transmission systems need to be fully considered in the design of the specific market rules. For example, there is likely a need to calculate opportunity costs for hydroelectric resources differently from thermal plants. These differences can affect market mitigation measures. However, we are concerned about whether different market designs can be in place in the Northwest and the rest of the West, and ask for comment on whether the entire West must have a common set of market rules to eliminate seams and prevent manipulation.

220. In the SMD Tariff we propose to include several different types of Congestion Revenue Rights to allow customers to protect against congestion costs. For example, one concern that we have heard from customers and suppliers in the Northwest is that a receipt point-to-delivery point Congestion Revenue Right may not work to effectively manage congestion on a system that utilizes several different hydroelectric facilities on a contingent basis to serve the same delivery points. A Congestion Revenue Right that recognized the contingent nature of the supply sources would be more valuable to customers in this instance. We believe that developing these types of Congestion Revenue Rights is possible and we propose to work with the regions to develop variations to meet regional needs. The congestion management system that we propose is flexible enough to accommodate these types of regional variations. Such variation and flexibility should not impinge on the development of a seamless electric grid.

2. LMP and Energy Markets

221. To implement LMP, the Independent Transmission Provider must operate an energy market to determine the marginal cost of redispatch. We propose to require that the Independent Transmission Provider operate both a day-ahead and a real-time energy market to manage congestion.

222. The Commission proposes to use real-time markets for energy to resolve energy imbalances. Under the proposal, the transmission customer would be charged the real-time price of energy for any imbalance, i.e., the difference between the energy the transmission customer schedules a day ahead on the system and the amount that it takes off the system in real time. The real-time price of energy is determined through a security-constrained, bid-based energy market run by the Independent Transmission Provider. The Independent Transmission Provider uses the bids to select the lowest-cost energy within the operational limitations of the transmission system. These same procedures will be used to resolve imbalances for all users of the transmission system.

223. The Commission also proposes that the Independent Transmission Provider operate a security-constrained, financially binding day-ahead energy market that is operated together with a day-ahead scheduling process for transmission service.¹²⁷ The

¹²⁷The operation of both a financially binding day-ahead market in conjunction with a financially binding real-time market is also known as a multi-settlement system.

day-ahead market for energy will allow the Independent Transmission Provider to manage congestion that arises in the day-ahead scheduling process.¹²⁸

224. The day-ahead energy market is a bid-based market. Sellers submit bids that indicate the quantities of power they will offer for sale in each hour of the next day and the price for that power at each location (node).¹²⁹ The price for the power may vary based on the quantities that are offered for sale. The differences in bid prices recognize that a generator's marginal cost of producing power can vary at different quantity levels because it operates more efficiently at certain output levels than others. Also, at the highest output levels, there may be additional opportunity costs because of an increased risk of a unit outage. Buyers also submit bids indicating the quantities they desire to purchase in each hour of the day. Buyers may also indicate the maximum price they are willing to pay for those quantities.

225. Under the Commission's proposal, buyers are not required to procure energy through the day-ahead energy market. A load-serving entity may procure all of its power through bilateral transactions, in the transmission provider's spot markets, or by

¹²⁸Such markets are currently operated by the New York ISO and PJM. California ISO and ISO-New England are planning on adding this feature to their market design.

¹²⁹The bids usually take the form of a bid curve that shows the bid price and quantity between the unit's minimum output and its maximum output. Usually the prices are relatively flat over the normal operating range of the unit. As quantities approach the maximum output the prices usually increase very rapidly.

generating its own power.¹³⁰ However, a load-serving entity may use the day-ahead market if it needs to acquire additional power or the price of power through the day-ahead energy market is lower than the price of power under an existing bilateral contract or the cost of generating its own power. A generator may also buy power through the day-ahead market. It would do this if it could buy the power more cheaply than generating to satisfy a bilateral contract obligation or if a forced outage requires it to procure power to satisfy a contract obligation.

226. The Commission proposes to require Independent Transmission Providers to allow buyers and sellers to submit purely financial bids, a feature that currently exists in the day-ahead markets run by PJM and New York ISO. These financial bids to buy or sell power are not backed by actual generation resources nor are they backed by actual load. Rather, these transactions are used to bring the prices in the day-ahead market and in the real-time market closer together. For example, suppose that the day-ahead price is consistently lower than the corresponding real-time price. Entities may therefore want to submit financial bids to buy energy in the day-ahead market at the lower price, and submit a corresponding bid to sell in the real-time market at the higher price, thereby making a net profit on the two transactions. The additional buyer bids in the day-ahead market would tend to increase day-ahead prices, while the additional supply bids in the real-time market would tend to reduce the real-time prices. The result is that the price

¹³⁰These transactions must still be scheduled through the day-ahead market and are subject to congestion costs if they do not have Congestion Revenue Rights.

differences in the two markets would shrink, as would the profits of sale. This process benefits the market. It helps market participants make better decisions in advance – in the day-ahead time frame – that will affect how much electricity they will sell or buy, because the day-ahead price becomes a more accurate gauge of what the real-time price will be.

227. The day-ahead energy market is operated together with the congestion management system and the day-ahead scheduling process for transmission service. The Independent Transmission Provider will determine market clearing prices for each hour in the day-ahead energy market based on the sale and purchase bids that are submitted. The market clearing price is the bid of the last unit of supply needed to satisfy the demand, i.e., the highest bid that is accepted. The market clearing price at a location is paid to all suppliers at that location that are selected in the auction and is paid by all buyers at that location that purchase through the auction.

228. We believe there are important differences between Standard Market Design and the market design that was in effect in the California ISO when it experienced problems in the energy markets in 2000 and 2001. First, Standard Market Design is premised on the use of bilateral contracts. While LSEs may purchase energy in the spot markets, these purchases should constitute a small percentage of their actual purchases. In contrast, the California market design required the LSEs to purchase the bulk of their energy needs through the spot markets. Second, Standard Market Design includes a forward-looking long-term resource adequacy requirement to avoid the types of supply shortages that

adversely affected California. Third, as discussed in more detail in Appendix E, Standard Market Design includes trading rules, a congestion management system, market power mitigation measures, and market power monitoring to address the manipulation strategies encountered in the California markets.

229. In determining market clearing prices, the Independent Transmission Provider factors in the operational limitations of the transmission capacity, such as congestion and reactive power needs, to ensure that the units that set the market clearing prices are consistent with the transmission system operations (i.e., a security-constrained dispatch).¹³¹ Because LMP is used as the congestion management system, the market clearing prices are the prices for energy delivered to each location or node on the system. If there is no congestion on the transmission system, the same market clearing price for energy will apply throughout the system.

230. The day-ahead market would be financially binding. This means that a seller that is selected in the day-ahead market is obligated to actually provide the power in real time or in real time it will be charged the cost of procuring the shortfall through the real-time

¹³¹It is important that the schedule developed through the day-ahead market be physically feasible, i.e., consistent with reliable transmission limitations. If it were not, then it would be necessary to make separate congestion payments to suppliers in real time to change their output so that the real-time schedule was consistent with reliable transmission limitations. This would provide an incentive for suppliers to create congestion in the day-ahead market so that they could receive payments in real time to relieve congestion.

market.¹³² The day-ahead market is also financially binding on buyers.¹³³ This reduces certain opportunities for strategic bidding and thus, market manipulation.

231. Years of experience with organized markets makes it clear that a day-ahead market is a best practice that must be included in the Standard Market Design. The development of a day-ahead schedule for energy and transmission service, including certain ancillary services, provides reliability benefits. It allows the Independent Transmission Provider to have advance warning to ensure that sufficient units are committed to serve the projected load. For example, if the Independent Transmission Provider believes that load has not scheduled sufficient transmission service or energy purchases in the day-ahead markets, it can commit additional units to be available in real time. Because of their operating characteristics, different types of generation units have differing levels of start-up costs as well as different lead times to be available in real time. The day-ahead market gives the Independent Transmission Provider information on unit availability, costs and system

¹³²For example, assume in the day-ahead market a generator agreed to sell 50 MW for the hour running from 9:00 am to 10:00 am at a price of \$30 Mwh. In the day-ahead market the generator would receive \$1,500 (\$30 times 50) for that sale. In real time, the generator only delivered 20 MW during that hour. The real-time price of energy in that hour was \$40 MWh. The generator would be charged \$1200 for its 30 MW shortfall in real time (30 times 40). Thus, the generator would receive a total net payment of \$300.

¹³³For example, assume that a load-serving entity buys 40 MW in the day-ahead market for the hour 10:00 am to 11:00 am at a price of \$30 Mwh. In the day-ahead market the load-serving entity would pay \$1200 (40 times 30) for that purchase. In real time the load-serving entity only took 35 MW in that hour. The real-time price of energy for that hour was \$25. The load-serving entity would effectively sell back the excess power (5 MW) at the real-time price (\$25), \$125. Thus, the load-serving entity would pay a net total of \$1075.

needs well before real time so the Independent Transmission Provider has more options available to ensure reliability and reduce costs in the real-time market.

232. Finally, the day-ahead market provides an important platform for market power mitigation. We propose several mitigation measures to ensure that there is a well-functioning spot market for wholesale power. These spot markets will result in price transparency, so buyers and sellers can see that market clearing prices are set in a fair and predictable manner. While the real-time market will be a transparent market, real-time prices may not be known until after the fact or at most five to ten minutes before real time. This gives buyers and sellers little chance to react to prices. In contrast, a day-ahead market provides a transparent spot market that allows buyers and sellers to engage in additional commercial transactions before real time. Thus, a day-ahead market helps liquidity and is likely to be less volatile than the real-time market.

233. The Independent Transmission Provider will also establish hourly prices for certain ancillary services, which may differ by location to the extent that ancillary service requirements differ by location. Since the same supply resources can often be used to provide either energy or ancillary services, energy and ancillary services should have compatible market designs. Otherwise, there would be an incentive to sell one type of product over another. Since both are needed, a compatible system allows the supplier to sell energy or ancillary services, whichever is the most efficient use of the supply resources. This yields the lowest total costs to customers.

234. As explained further below, the Independent Transmission Provider will need to manage congestion in two time frames: (1) during the day-ahead scheduling process, and (2) during real-time operations. The Independent Transmission Provider will conduct separate auctions to manage congestion in each time frame. In the day-ahead auction, for each hour of the following day the Independent Transmission Provider will take bids to buy and sell energy, to provide certain ancillary services, and to purchase transmission service between identified receipt and delivery points. The Independent Transmission Provider will consider the bids for energy, transmission service and ancillary services simultaneously. Based on those bids, the Independent Transmission Provider will develop a schedule that maximizes the economic value (as reflected in the bids) of the transactions over the entire day-ahead period, in light of the amount of Available Transfer Capability and any resulting transmission congestion and losses. The Independent Transmission Provider will also establish prices for transmission service, energy and ancillary services that clear the markets.

3. Congestion Revenue Rights

235. Under LMP, transmission usage prices will vary based on the price of relieving transmission congestion and losses. Rather than using a system of physical reservations, a system of financial rights called Congestion Revenue Rights will be used to give customers the ability to protect themselves against congestion costs.

236. The initial allocation process for Congestion Revenue Rights will be done through compliance filings that allow for different treatment within each region. Since this must

occur before Standard Market Design is implemented, we have not addressed initial allocation in the SMD Tariff, but it is discussed in Section IV.E.3.e below. This section describes allocation processes that would be used after the initial allocation has been done.

a. General Features

237. We propose to require that Independent Transmission Providers offer Congestion Revenue Rights of several types (one that we will mandate now and others that should be offered upon customer request when technically feasible) that allow transmission customers to obtain protection against uncertain future congestion charges. We have added a new section to the SMD Tariff that describes the types of Congestion Revenue Rights that would be available, how one acquires Congestion Revenue Rights after the initial allocation and how Congestion Revenue Rights provide protection against congestion costs (Part II.D., Congestion Revenue Rights). The proposed provisions are discussed below.

238. The Independent Transmission Provider would be required to offer Congestion Revenue Rights for all of the transmission transfer capability on the grid, but it would not be allowed to sell more rights than can be accommodated. Congestion Revenue Rights would be available over a variety of terms, such as weekly, monthly, yearly and perhaps for longer terms. If an entity pays to construct new generation or transmission facilities that add transfer capability, and the costs of the upgrade are not rolled in, the entity would receive the Congestion Revenue Rights associated with the new transfer capability. In the

past the Commission has allowed credits for upgrades; is there still a role for credits under Standard Market Design?

239. Customers that have not acquired Congestion Revenue Rights in advance could schedule transmission service in the day-ahead market, but they would not have the Congestion Revenue Rights protection against congestion costs.

240. We propose that Congestion Revenue Rights be made available first in the form of receipt point-to-delivery point obligation rights, which we propose to mandate now, and later in the form of receipt point-to-delivery point option rights and flowgate rights.

Currently, in PJM and New York ISO only receipt point-to-delivery point obligations are offered. However, there has been considerable interest expressed by market participants in other types of Congestion Revenue Rights. For example, the Midwest ISO is considering offering a package of Congestion Revenue Rights that are similar to what we are proposing. Also, PJM is considering offering receipt point-to-delivery point options. Offering several different types of Congestion Revenue Rights would make the system more flexible and better able to adapt to the needs of specific customers. Also, certain types of Congestion Revenue Rights may be more valued in different regions of the country based on the physical configuration of the transmission system and the types of resources connected to that system. Various technical papers over the last few years have examined offering these alternate rights simultaneously and concluded that it is feasible

under the conditions now specified in the SMD Tariff.¹³⁴ Therefore, we believe the tariff should provide this flexibility.

b. Types of Congestion Revenue Rights

241. The SMD Tariff describes the characteristics of each of the types of Congestion Revenue Rights. These descriptions are summarized below.

(1) Receipt Point-to-Delivery Point Rights.

242. A receipt point-to-delivery point right is a right that is specified by a receipt point (which can be a generator node, an aggregation of generator nodes, an interface, a trading hub, or any other collection of nodes) and a delivery point (which can be a delivery node, an aggregation of delivery nodes, an interface, or a trading hub), and the power in MW that is transmitted from the receipt point to the delivery point for a period of time (e.g., one hour).

243. A receipt point-to-delivery point right entitles the holder to the day-ahead congestion revenues associated with transmission service from the receipt point to the delivery point.¹³⁵ In addition, during any period when the demand for transmission

¹³⁴See, e.g., Hogan, William W., Financial Transmission Rights Formulations, Center of Business and Government, John F. Kennedy School of Government, Harvard University, Cambridge, MA (March 31, 2002); Chao, Hung-Po, Peck, Stephen and Wilson, Robert, Flow-based Transmission Rights and Congestion Management, The Electricity Journal, pp. 8, 13 and 38-58 (2000); and Chao, Hung-Po and Peck, Stephen, A Market Mechanism for Electric Power Transmission, Journal of Regulatory Economics (July 1996).

¹³⁵The right is direction-specific. The holder is entitled to congestion revenues
(continued...)

service cannot be met with Available Transfer Capability (i.e., because there are too many customers who have indicated that they want transmission service at any price), holders of receipt point-to-delivery point rights would receive priority over other market participants in scheduling transmission service between the receipt point and delivery points designated in their rights.

244. A receipt point-to-delivery point right would provide the holder with the right to schedule transmission service of the specified amount of power (MW) in the day-ahead market from the receipt point to the delivery point without paying any net charges for congestion (although the holder would need to pay a charge for losses). The reason is that every customer would be entitled to inform the Independent Transmission Provider to schedule its transmission service regardless of the congestion charge. In that case, the customer would be charged for congestion (as well as for losses). But a self-scheduled customer holding a receipt point-to-delivery point right for at least the same amount of power between the same receipt and delivery points would receive congestion revenues that fully offset the congestion charge.

(2) Obligations and Options

245. Receipt point-to-delivery point rights can take the form of obligations or options. The difference between obligations and options becomes important when congestion occurs in the opposite direction from the right, that is, when there is congestion from the

¹³⁵(...continued)
from the receipt to delivery point, not from the delivery point to the receipt point.

delivery point to the receipt point. In this case, congestion revenues in the direction of the right are negative. Under a receipt point-to-delivery point obligation, the Congestion Revenue Rights holder in that case would be required to pay the negative congestion revenues to the Independent Transmission Provider. Under a receipt point-to-delivery point option, the Congestion Revenue Rights holder would not be required to pay the negative congestion revenues to the Independent Transmission Provider. Existing firm point-to-point transmission contracts under the Order No. 888 pro forma tariff do not require contract holders to transmit energy and, thus, are similar to Congestion Revenue Rights that are options.

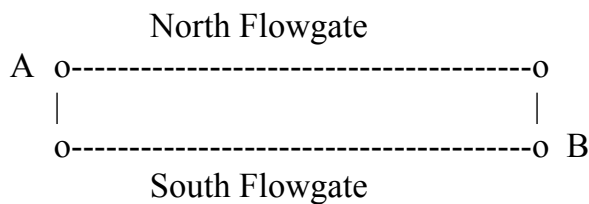
(3) Flowgate Rights

246. A flowgate is a particular transmission facility or group of facilities (e.g., an interface). A flowgate right specifies a portion of the transmission capacity over that flowgate in a specified direction. A flowgate right entitles the holder to the day-ahead congestion revenues associated with the specified power flows over the flowgate in the

specified direction.¹³⁶ Unlike a receipt point-to-delivery point obligation, a flowgate right would never require the holder to make congestion payments. The congestion revenue associated with a flowgate in a specified direction would equal the additional net economic value to market participants that would result by incrementally increasing the flowgate's capacity in the specified direction. That additional net economic value may be either positive (i.e., when the flowgate is congested) or zero (i.e., when the flowgate is not congested), but it would never be negative.

247. Receipt-point-to-delivery-point rights offer the transmission customer with long-term energy contracts the best way to protect itself against hourly congestion costs.

¹³⁶Consider, for example, a very simplified transmission network that connects two points, A and B, with two different but interconnected transmission lines, a northern line and a southern line, as shown below:



Each transmission line could be a separate transmission or flowgate, and separate flowgate rights could be issued for each line. The holder of a flowgate right on the northern line from west to east would be entitled to the congestion revenues associated with that line in the west-to-east direction. However, holding a flowgate right on the northern line would not entitle the holder to congestion revenues associated with the southern line. Hence, if transmission service results in energy flows over several flowgates, the buyer must obtain sufficient rights on each flowgate to obtain protection from congestion charges. By contrast, the holder of a receipt point-to-delivery point right from west-to-east (i.e., from A to B) would be entitled to congestion revenues in the west-to-east direction regardless of whether the northern or the southern lines were congested and thus would have a complete hedge for this transaction

However, many transmission customers may be meeting their loads' needs with a portfolio of generators scattered around a regional electricity market. Such customers may be seeking a more flexible type of right than the receipt-point-to-delivery point right (which is typically only reconfigured on a monthly basis and which can be traded on the secondary market most easily if another customer requires the same points as specified in the right). The major market advantage of the flowgate right is that since there are fewer congested flowgates than possible under receipt-point-to-delivery-point rights, transmission customers can focus their rights on the key congested flowgates. This allows for coverage of much of the congestion charges (in some estimates, between 80 percent to 90 percent). However, the flowgate rights may not provide a complete protection against congestion charges for a receipt point-to-delivery point energy transaction, since the congestion revenues may differ from the congestion charges.

c. Requirement for Offering Rights

248. At the start of Network Access Service, the Independent Transmission Provider would be required to offer receipt point-to-delivery point obligations. These rights are the easiest to implement because they are already in wide use. While we want the market to develop additional choices for customers, we are concerned about requiring implementation of numerous types of rights, including types of Congestion Revenue Rights that have not yet been tested by an ISO or RTO, when Standard Market Design is first implemented. Because there is no experience with the other types of rights, we propose not to require the Independent Transmission Provider to offer them initially.

However, upon the request of market participants, the Independent Transmission Provider would be required to offer receipt point-to-delivery point options and flowgate rights as soon as technically feasible.

249. Additionally, Congestion Revenue Rights could be offered for various terms, e.g., one month or five years. Some customers may desire Congestion Revenue Rights with multi-year terms to correspond to the terms of long-term power contracts, including contracts used to satisfy the resource adequacy requirement discussed in Section J. At the same time, it may be difficult for the market to value long-term Congestion Revenue Rights until a region has actual operating experience under an LMP congestion management system. This could create problems in an area that auctions all Congestion Revenue Rights and allocates the auction revenue rights to load. We seek comment on whether the Commission should require the Independent Transmission Provider to offer multi-year Congestion Revenue Rights when Standard Market Design is first implemented. Additionally, we seek comment on whether the Independent Transmission Provider should be required to offer Congestion Revenue Rights with terms tied to the planning horizon used in the region to satisfy the resource adequacy requirement.

d. Funding for the Congestion Revenue Rights

250. As explained above, holders of Congestion Revenue Rights would be entitled to receive congestion revenues associated with transmission congestion in each hour of the day-ahead market. The aggregate amount of Congestion Revenue Rights issued by the Independent Transmission Provider would be the amount simultaneously feasible based

on Available Transfer Capability under normal operating conditions. As a result, during normal operating conditions, the Independent Transmission Provider would collect enough congestion charge revenue from users of transmission service in the day-ahead market to fully pay the day-ahead congestion revenues owed to holders of Congestion Revenue Rights. Indeed, the Independent Transmission Provider might collect a surplus of revenue in some hours during normal operating conditions. However, when a significant amount of transmission facilities are out of service, so that less transmission service can be provided, the Independent Transmission Provider may collect less congestion charge revenue from transmission users than the amounts owed to Congestion Revenue Rights holders.

251. There are two ways to handle this revenue shortfall. First, the amount of congestion revenues paid to the holders of Congestion Revenue Rights may have to be reduced. As a result, the customer may only be able to protect against a portion (e.g., 95 percent) of its congestion costs in the day-ahead market. Alternatively, the customer that has a Congestion Revenue Right could receive full protection against congestion costs and the revenue shortfall would be assigned to the transmission owner. We propose to use the latter approach. When such revenue deficits arise, we propose that such deficits be made up by transmission owners whose transmission facilities are out of service. We would, however, include an exception for outages due to force majeure events, since our intent is to reward transmission owners for proactively maintaining their transmission

facilities.¹³⁷ Assigning revenue deficits in this way would encourage transmission owners to take steps to minimize forced transmission outages and to schedule maintenance outages so as to minimize their effect on congestion costs. Assigning congestion revenue surpluses to transmission owners may also encourage them to minimize outages. However, such a policy may also create an interest on the part of transmission owners in maintaining congestion, and thus may discourage them from building needed transmission expansions. We propose that any revenue surpluses be paid to transmission owners, but we seek comment on the potential of this policy to discourage transmission expansions and if alternative mechanisms should be used to distribute the revenue surpluses.

e. Auctions and Resales of Congestion Revenue Rights

252. We believe it is important that there be an active secondary market for Congestion Revenue Rights. This will allow a market mechanism for customers that have Congestion Revenue Rights to acquire new ones or to sell Congestion Revenue Rights they no longer need. Additionally, this provides a way for market participants that do not have Congestion Revenue Rights to acquire them. Market participants would be allowed to resell any Congestion Revenue Rights that they have been awarded for the full term of the rights or for a part of the term. Resales could be transacted bilaterally between willing buyers and sellers. In addition, we propose to require that the Independent Transmission

¹³⁷As a result, in the event of force majeure the Congestion Revenue Rights would not be fully funded.

Provider conduct periodic auctions of Congestion Revenue Rights. The Independent Transmission Provider's auction would allow holders of rights to resell their Congestion Revenue Rights in an organized market. This would provide greater price transparency for these rights than if all sales were conducted through bilateral transactions. Moreover, the auctions would provide the ability to reconfigure Congestion Revenue Rights into different receipt and delivery points, or into different types of rights (e.g., receipt point-to-delivery point options, obligations, or flowgate rights). This would allow Congestion Revenue Rights holders to change their Congestion Revenue Rights if for example they decided to switch suppliers. The auctions would also allow Congestion Revenue Rights associated with other transmission capacity that becomes available (such as through the expiration of previously issued Congestion Revenue Rights) to be sold.

253. In the auctions, buyers and sellers would submit bids that specify the type of Congestion Revenue Rights desired to be bought or sold, the location, term and price. The Independent Transmission Provider would select the combination of bids that maximizes the economic value of the transactions for the participants. In so doing, the Independent Transmission Provider must reconfigure the Congestion Revenue Rights offered for sale in a way that maintains the simultaneous feasibility of the Congestion Revenue Rights. That is, the types and/or locations of the Congestion Revenue Rights offered for sale may differ from those that are purchased. The Independent Transmission Provider would establish market-clearing prices for each Congestion Revenue Right

bought or sold. Each seller would receive the market-clearing price for the rights that it sold, and each buyer would pay the market-clearing price for the rights that it purchased.

**f. Including Energy and Ancillary Services in the
Congestion Revenue Rights Auctions**

254. The time period covered by the Congestion Revenue Rights sold in auctions would be a month or longer. We propose that an Independent Transmission Provider would be permitted, but not required, to conduct pre-day-ahead auctions for energy and ancillary services. Under such auctions, market participants could offer to buy and sell energy and ancillary services at specific locations on a forward basis for a specified time period, such as for a month or a year. Participation in these pre-day ahead markets, as in all markets, would be on a voluntary basis. Such purchases and sales of energy and ancillary service would require use of the transmission system, just as sales of Congestion Revenue Rights would. Thus, in conducting pre-day-ahead auctions, the Independent Transmission Provider would allocate transmission capacity among competing demands for Congestion Revenue Rights, forward energy and forward ancillary services so as to maximize the economic value of the winning bids. The Independent Transmission Provider would establish market-clearing prices for forward energy and ancillary services at each location, as well as market-clearing prices for Congestion Revenue Rights.

255. A potential benefit of pre-day-ahead auctions is that they could more easily maximize the economic benefits of transmission capability by considering a greater array of competing uses of the transmission grid. They could also provide a convenient, central

market forum for buyers and sellers to arrange forward trades of energy and ancillary services. They could provide transparency and liquidity (and thus protection against manipulation) in long-term markets where liquidity has recently been reduced.

F. Day-Ahead and Real-Time Market Services

256. This section sets forth the bidding, scheduling, price determination, and settlement provisions necessary to implement LMP in the day-ahead and real-time markets for energy, regulation and both operating reserves. In this section, we lay out the basic elements that would be used for congestion management and operation of the spot markets.¹³⁸

1. Design of the Day-Ahead Markets

257. We propose that the Independent Transmission Provider operate day-ahead and real-time markets for energy and certain ancillary services in conjunction with its scheduling of transmission service day ahead and in real time. These markets would allocate transmission and generation capacity among competing uses in different markets through LMP pricing. For example, the markets would determine how much transmission capacity would be allocated for transmission service to market participants completing bilateral energy transactions, for use by the Independent Transmission Provider in completing energy sales and purchases through its bid-based energy markets,

¹³⁸Part I of the SMD Tariff includes a definition of the terms related to market services. In addition, as we use the term "supplier" or "seller" in this Section, the definition we are using includes both generators and demand-side resources that satisfy the Independent Transmission Provider's applicable requirements.

and for providing ancillary services. The markets should be operated jointly to ensure that transmission and generation capacity is allocated where it is most valuable, and to ensure that the prices for the products and services are internally consistent.

a. Scheduling Transmission Service Day Ahead

(1) General Features

258. Each day the Independent Transmission Provider would accept requests to schedule transmission service to support bilateral energy transactions or customer-owned generation for each hour of the following day. A customer desiring transmission service would be required to submit a scheduling request in a standardized form specified by the Independent Transmission Provider. For each requested transmission service, the scheduling request would indicate the receipt point and the delivery point of the bilateral energy transaction or customer-owned generation, the amount of power (MW) to be transmitted and the time period. To facilitate the ability of demand to respond to price signals, transmission customers will be given several ways of indicating their willingness to change their consumption based on congestion costs and marginal losses: (1) customers (whether or not they hold Congestion Revenue Rights) would be allowed to specify in their scheduling requests the maximum transmission usage charge (reflecting the costs of congestion and marginal losses) at which the customer desires service;¹³⁹ (2)

¹³⁹For example, when transmission usage prices become sufficiently high, customers holding receipt point-to-delivery point Congestion Revenue Rights may prefer not to schedule transmission service between their designated receipt and delivery points. (continued...)

customers would be allowed to specify the maximum congestion charge component of the transmission usage charge at which they desire transmission service, or above which they are unwilling to pay any congestion costs; or (3) customers (whether or not they hold Congestion Revenue Rights) could submit a bid that states a desire for transmission service to be scheduled regardless of the transmission usage charge. This option may be useful for a holder of a Congestion Revenue Right that desires to schedule transmission service that uses the receipt point-to-delivery point combination covered by that Congestion Revenue Right.

259. Another way that transmission customers will be able to respond to price signals is by submitting multi-hour block bids, requesting transmission service for a block of consecutive hours and indicating the maximum price for the entire multi-hour period. For example, a multi-hour block bid might specify that the customer desires 10 MW of transmission service from receipt point A to delivery point B in each hour from 1:00 pm to 6:00 pm as long as the price per MW for the entire 5-hour period does not exceed \$10. Such a bid would be accepted if the sum of the hourly transmission usage prices for each of the 5 hours did not exceed \$10. Otherwise, the entire bid would be rejected. This option allows a customer, for example an industrial customer in a state with retail access, to indicate that it is willing to reduce its transmission usage if the prices for a multi-hour

¹³⁹(...continued)

Instead, the customers may prefer to receive the applicable congestion revenues. Customers could communicate these preferences through price-bids.

period are above a specified level. This feature has not been put in practice in any of the bid-based markets operated by ISOs. We seek comments on its merit and any implementation difficulties.

260. The Independent Transmission Provider would consider these transmission scheduling requests in conjunction with bids submitted in its day-ahead energy and ancillary service markets. Based on all of these, the Independent Transmission Provider would accept the set of energy bids and scheduling requests and develop a day-ahead schedule that maximizes the economic value for all market participants. The Independent Transmission Provider would also establish transmission usage prices for each hour of the next day that are the same as the implicit transmission usage price included in the set of locational energy prices (i.e., the difference in the price of energy at the receipt point and at the delivery point, which reflects both congestion and losses).

261. The Independent Transmission Provider would schedule all requests for transmission service since these users have agreed to pay any applicable congestion charges. The Independent Transmission Provider would also schedule all requested transactions where the transmission usage charge was below the amount the customer indicated it was willing to pay.

262. Customers with Congestion Revenue Rights would receive congestion revenues that help offset any congestion charges paid as part of the transmission usage charge. The amount of the congestion revenues received (and the associated protection against congestion charges) would depend on the specific Congestion Revenue Rights held. A

customer holding receipt point-to-delivery point Congestion Revenue Rights for a certain amount of power between a delivery and receipt point that matches its day-ahead transmission schedule would receive congestion revenues that exactly offset its congestion charges, so that its net bill would reflect no congestion charges (although it would be charged for losses).

263. The above process would be used for scheduling transmission service on a daily basis. Some customers, particularly those with Congestion Revenue Rights, may desire to schedule the same exact service over a longer period to save on administrative costs. The Commission seeks comments on whether a customer should be allowed to provide a schedule for multiple days or have a standing scheduling request that would remain in effect until changed by the customer. Any schedule request, once scheduled by the Independent Transmission Provider would become financially binding on the customer at the close of each day's day-ahead market.

(2) Transmission Service Across Borders

264. Transmission service across the border of adjoining Independent Transmission Providers' service areas – from a point of receipt in one service area to a point of delivery in another – requires coordination between the affected Independent Transmission Providers. When transmission congestion exists between a point of receipt and a point of delivery in different service areas, managing the congestion becomes more difficult because more than one Independent Transmission Provider is involved.

265. There are at least two methods for arranging for transmission service across borders – physical reservations (i.e., continuing firm point-to-point reservations of transfer capability), and scheduling of service consistent with internal transactions under Network Access Service (scheduling of transmission and financial bidding). We propose to treat transmission service across borders in the same way as internal transactions. Thus, like internal transactions, an importing or exporting customer could either schedule transmission service and agree to pay the transmission usage charge regardless of the level or submit a bid that limits its congestion exposure. Under the first method, the transmission customer would submit to each Independent Transmission Provider a request to be scheduled for transmission service to and from the border, regardless of the applicable transmission usage charges that it will be assessed. The customer would be scheduled unless congestion arose that could not be relieved through redispatch or some other means. Under the second method, financial bidding, the customer would submit a price bid to each Independent Transmission Provider indicating the maximum transmission usage charge that it is willing to pay for transmission service on each side of the border. The customer would be scheduled if its price bid on each side of the border was at or above the applicable transmission usage charge. Under either method, if the customer's transaction is scheduled, the customer would pay the applicable transmission usage charges to and from the border. We propose to make both options available to transmission customers, because each option may provide benefits to customers. We

would prefer "one-stop shopping" with Independent Transmission Provider coordination; we seek comment on whether this can be done?

266. Recently we accepted a prescheduling option for service across borders that was proposed by the New York ISO.¹⁴⁰ A prescheduling option would give a customer certainty prior to the day-ahead market that it could transmit power across a border. Under the New York ISO's prescheduling option a customer may schedule such a transaction up to eighteen months in advance of the dispatch day. A customer that requests a prescheduled transaction agrees to pay the applicable market clearing transmission usage charge. Once submitted, the transaction would be financially binding unless the New York ISO permits the customer to withdraw the prescheduled transaction. We seek comment on whether a similar prescheduling option should be included in Standard Market Design.

b. Transmission Losses

267. When energy is transmitted from a point of receipt to a point of delivery, some of the energy is lost due to resistance on the wires. These transmission losses are a cost of transmission and commonly are recovered on an average cost basis from all transmission customers. As noted earlier, we are proposing that energy prices and the associated transmission usage charges be based on marginal costs, in order to promote economic efficiency. We seek comment on whether transmission losses should be recovered on the

¹⁴⁰New York Independent System Operator, Inc., 99 FERC ¶ 61,292 (2002).

basis of the marginal cost of losses or if they should be recovered on the average cost of losses. There are advantages and disadvantages to each approach. Using marginal losses would promote a more efficient use of the transmission system. However, as discussed below, charging marginal losses will collect surplus revenues that must then be returned to transmission customers. On the other hand, the advantage of charging average losses is simplicity. If average losses are charged, the losses collected from customers would equal actual losses. There would be no need to create a mechanism to return surplus losses.

268. For customers purchasing transmission service to complete bilateral transactions, we see value in allowing transmission customers to pay for their assigned losses either in cash or in kind. To pay in cash, the customer would pay the market price for its assigned MWhs of losses, which would be included in the applicable transmission usage charge. Thus, the MWh of energy injected at the point of receipt would equal the MWh withdrawn at the point of delivery. The transmission provider would procure the energy used for losses from its energy market. To pay in kind, the customer would supply energy at the point of receipt in the amount of its assigned losses. Thus, the MWhs injected at the point of receipt would exceed the MWhs at the point of delivery by the amount of the assigned losses, and the customer would pay in cash only the congestion component of the transmission usage charge.¹⁴¹ We note, however, that some

¹⁴¹The amount of energy needed for losses would not be known until the close of
(continued...)

commenters in our outreach process expressed concern that allowing customers to provide losses in kind may unduly complicate the scheduling process, especially for transactions that involve multiple Independent Transmission Providers. We seek comment on whether transmission customers should have the choice of paying for losses in cash or in kind, or alternatively, whether all transmission customers should be required to pay for losses in cash.

c. Day-Ahead Energy Market

(1) General Features

269. We propose that the Independent Transmission Provider be required to run a voluntary, bid-based, security-constrained day-ahead energy market. "Voluntary" means that market participants do not have to buy or sell in the day-ahead energy market. The day-ahead market we are proposing provides customers with additional supply choices. It is not intended to substitute for other longer-term arrangements that customers may use to purchase supplies such as bilateral transactions or use of a customer's own generation. Thus, market participants would be able to schedule bilateral transactions and/or their

¹⁴¹(...continued)

the market. For transactions in the day-ahead market, the Transmission Provider would inform each customer that wishes to supply losses in kind (after the close of the day-ahead market) of the amount of its assigned losses (in MWh), and that amount would be included in the customer's day-ahead schedule. For transactions in the real-time market, the Transmission Provider could provide an estimate in advance of the amount of each customer's assigned losses. However, since actual marginal losses would not be known until after the fact, the customer would be charged or credited at the applicable LMP for any under- or over-provision of losses.

own generation rather than bid into the day-ahead energy market. "Bid-based" means that participants may submit offers to buy or sell quantities of energy into the market and may specify the prices at which they are willing to transact. This provides an organized and transparent system for the Independent Transmission Provider to determine the marginal cost of relieving transmission congestion. "Security-constrained" means that the Independent Transmission Provider, in the energy auction process, takes account of all system constraints, such as contingency limits, needed for reliable system operations and develops a schedule that does not violate such constraints. This is necessary to ensure that the day-ahead schedule is physically feasible. Otherwise, the Independent Transmission Provider might be required to make additional payments in real time to relieve congestion, which could provide an incentive for market participants to create congestion in the day-ahead market to receive these payments in the real-time market.¹⁴² The market should allow full participation by both the supply side and the demand side of the market.

(2) Bidding and Scheduling Rules

270. Each day, the Independent Transmission Provider would accept bids to sell and buy energy for each hour of the following day. Participants desiring to sell or buy energy would submit a bid in a standardized form.

¹⁴²See the discussion of this issue in Appendix E.

271. Each seller's bid would indicate the amount of power (MW) offered to be sold, the receipt point, and the time period. In addition, each seller would be allowed to submit multi-part bids that separately specify bid prices for start-up, no-load, and energy, as well as technical characteristics such as ramp rates, minimum run times and minimum down times. Allowing suppliers' bids to include these items yields more detailed information that can improve the ability of the grid operator to dispatch suppliers with the lowest total cost. For example, if the supplier were required to submit a one-part bid it would need to include start-up costs in its energy bid, resulting in a higher energy price bid. However, a supplier submitting a bid that separately specified the energy bid and the start-up costs would not have to make these estimates and the grid operator would use the bids to dispatch the supplier with the lowest total cost. Suppliers would also be allowed to submit bids that are self-schedules, that is, that would indicate an amount to be supplied at a location regardless of the applicable energy price. The supplier would receive the applicable market clearing price for its energy. This option may be useful for suppliers with very high start-up costs such as nuclear facilities. Intermittent resources would be able to participate in the day-ahead market on the same basis as other resources.

272. Similarly, each buyer's bid would indicate the desired amount of power (MW) to be bought, the delivery point, and the time period. In addition, each buyer would be allowed to specify bid prices that indicate the quantities it is willing to purchase at alternative prices. Buyers would also be allowed to submit multi-part bids that indicate the time and price constraints under which they are willing to purchase energy. These

options would facilitate demand response programs because they allow the buyer to indicate the price at which it will voluntarily reduce its consumption. Buyers would also be allowed to schedule an amount to be purchased regardless of the applicable energy price.¹⁴³ Bids would not need to be tied to a physical generator or load resource.

However, for reliability purposes, bids would need to indicate whether they were purely financial bids or whether they were tied to a physical resource. This would permit market participants to bring day-ahead and real-time prices closer together, increasing the stability of both markets. This option should reduce price differences between these two markets.

273. Buyers and sellers would be able to submit different price bids for different hours of the day, and bids could vary from day to day. However, if market participants can exercise market power, limits may be imposed on bidding to mitigate market power, as discussed below in the section addressing market power monitoring and mitigation.

274. We propose a scheduling option to address the special conditions facing energy-limited resources such as hydroelectric and environmentally constrained thermal resources. These resources are limited in the amount of energy or the number of hours that they can produce energy over a period of time. As a result, production in one hour

¹⁴³Since energy prices have the potential to rise to very high levels, it may be necessary to require buyers that request energy without submitting a price bid to demonstrate to the Independent Transmission Provider in advance that they are financially capable of paying very high prices for such quantities. Alternatively, the Independent Transmission Provider could limit the amounts based on a buyer's creditworthiness.

may reduce the amount of energy that the resource can produce (and the associated revenue) in other hours. Energy-limited suppliers could submit bids in the day-ahead market that specify the amount of energy, or the number of hours, available for production over the next day. The supplier could then request the Independent Transmission Provider to schedule its energy in those hours of the next day when the energy price is highest. Such a scheduling feature would promote efficient scheduling because it would allow the energy-limited resource to be scheduled where its energy would have the greatest value, with maximum profit to the resource owner.¹⁴⁴ We recognize that the resource mix varies significantly from region to region and that some regions, such as the Northwest, have a greater amount of energy limited resources. We seek comment on whether other scheduling options or regional variations should be included for energy-limited resources in the tariff.

275. We recognize that intermittent resources such as wind power may also benefit from scheduling rules that recognize their inability to precisely control output. We recently approved a special mechanism for intermittent resources selling into the energy market run by the California ISO.¹⁴⁵ Under that mechanism, the intermittent resource and the California ISO work together to develop a schedule and procedures for accurately

¹⁴⁴While this scheduling feature is intended mainly for energy-limited resources, it would be available to all generators and would not be restricted to energy-limited resources, unless such restrictions are necessary to mitigate market power.

¹⁴⁵See California Independent Operator Corp., 98 FERC ¶ 61,327, order accepting compliance filing, 99 FERC ¶ 61,309 (2002).

forecasting the output of the resources. However, California ISO currently runs only a real-time market for energy and not both a day-ahead market and real-time market as proposed here. Also, the amount of power produced by intermittent resources within California is much larger than in many parts of the country. We propose to include the California ISO's scheduling option for intermittent resources as part of Standard Market Design. However, we seek comment on whether there is a better way to schedule intermittent resources.

276. Finally, in drafting the bidding and scheduling rules we have included several ways for demand to respond to prices. We recognize that several ISOs currently have demand response programs that operate differently. Under these demand response programs, the ISO pays end-users to reduce their demand if market clearing prices reach a certain level. We believe the direct approach of letting demand bid in the market will be less costly than a program where an end-user receives payments greater than the market clearing price to reduce its demand. We have not proposed to include these types of programs in the pro forma tariff although they could be included if the Independent Transmission Provider, in consultation with the state advisory committee and stakeholders, determined that they were necessary. Since the participation of demand in the market is critical for an effective wholesale market, we seek comment on whether the measures proposed are sufficient or if other measures should be included.

(3) Price Determination and Settlement

277. Based on the accepted bids included in the day-ahead schedule, the Independent Transmission Provider would establish day-ahead locational energy prices for each hour. The hourly energy price at each location would reflect the marginal cost (as reflected in bids) of producing and delivering energy to that location in that hour. Energy prices would be consistent with the transmission usage charges, so the difference in energy prices between two locations in an hour would reflect the cost of transmitting energy from one location to the other.

278. The Independent Transmission Provider would establish a single market-clearing energy price for each hour for each node on its transmission system. We believe it is important that energy prices be calculated for each node to avoid socialization of congestion costs and to reduce the possibility of manipulating the congestion management system.¹⁴⁶ The Independent Transmission Provider could also establish nodal prices for time intervals shorter than an hour. Nodal pricing would be used for both buyers and sellers in the day-ahead market.

279. Upon request of market participants, the Independent Transmission Provider would establish trading hubs. A trading hub is a virtual location where financial transactions may be arranged, whose hub price is the weighted average of energy prices at a specified set of nodes on the transmission system. A trading hub facilitates financial trading and aggregation of supplies from multiple sources. Creation of trading hubs

¹⁴⁶ See discussion in Appendix E of manipulation strategies involving congestion management.

should not lead to socialization of congestion costs, because the price for service at the trading hub is the weighted average of prices at the various nodes that are included in the trading hub. Energy may not be injected or withdrawn from the grid at a trading hub, since a hub does not exist at a physical location. But a hub may be named as an intermediate point between physical points of injection and withdrawal where financial energy trades may occur.¹⁴⁷ Also, at the request of market participants, the Independent Transmission Provider would establish zones that are the weighted average of energy prices at selected delivery nodes on the transmission system. This option would permit a load-serving entity to aggregate prices for deliveries to its various delivery nodes.

280. Each buyer and seller would transact at the applicable clearing price for the hour and time period. A seller that submits separate bids for start-up and no-load costs and is dispatched by the Independent Transmission Provider for any period during the day, will be assured that it will recover the start-up and no-load costs that it bid. If a seller's total bid costs (including start-up and no-load costs, as well as energy running costs) over the entire day are not fully covered by its revenues from selling at the hourly clearing prices, it would receive an additional payment (i.e., an "uplift" payment) for the net revenue shortfall for the day. Hourly energy prices would be based only on energy bids; start-up cost bids and no-load bids would not be used in calculating hourly energy prices. Thus, a generator may have legitimate start-up costs that are not fully covered by selling at the

¹⁴⁷ A good example of a trading hub is PJM's Western hub, where there are active spot energy and transmission rights markets, as well as bilateral markets.

hourly energy price over the day; paying uplift may be necessary to ensure that generators selected in the auction will receive revenues that fully cover their bid-costs.¹⁴⁸ Since the additional payments are a cost of providing supplies of energy and ancillary services in the Independent Transmission Provider's day-ahead market, we propose to recover the additional payments from entities that purchase energy and/or ancillary services in the Independent Transmission's Provider's day-ahead market. Any entity that does not buy any energy from the Independent Transmission Provider's day-ahead market on a given day, and that self-supplies all of its ancillary service obligations on that day, would not be assigned a share of the additional payment for that day.

281. The results of the day-ahead market would be financially binding on buyers and sellers. That is, sellers would be paid the applicable locational day-ahead price for energy scheduled to be sold in the day-ahead market, and buyers would pay the applicable

¹⁴⁸ For example, suppose that the Independent Transmission Provider needs to supply an additional 100 MW load in each of 20 hours over the next day. Two generators, A and B, are available. Generator A has energy costs of \$35/MWh, but must incur \$15,000 in start-up costs before beginning production. Generator B has energy costs of \$40/MWh, and has no start-up costs. Generator A's total cost of meeting the load would be \$85,000 (i.e., total energy costs of \$70,000 [$\$35/\text{MWh} \times 100 \text{ MWh} \times 20 \text{ hrs}$] PLUS start-up costs of \$15,000). Generator B's total cost would be \$80,000, comprised exclusively of energy costs (i.e., $\$40/\text{MWh} \times 100 \text{ MWh} \times 20 \text{ hrs}$). Generator B should be chosen because its total costs (\$80,000) would be less than Generator A's total costs (\$85,000). Suppose that the hourly clearing price in each hour is \$42/MWh. By selling 100 MWh in each of 20 hours, Generator B would receive total revenues of \$64,000 (i.e., $\$32/\text{MWh} \times 100 \text{ MWh} \times 20 \text{ hrs}$), which is \$6,000 less than its total bid-in costs of \$70,000. Generator A would thus need to receive a \$6,000 uplift payment in addition to its energy revenues. Paying \$6,000 in uplift is still cheaper for customers than the alternative of dispatching Generator B.

locational day-ahead price for energy scheduled to be bought in the day-ahead market. In addition, to the extent sellers and buyers fail to actually produce or take energy according to their respective schedules in real time, such imbalances would be settled at the applicable real-time energy price. Thus, a seller would pay the real-time LMP nodal price for any scheduled energy that it fails to deliver in real time to its bid delivery point. Similarly, a buyer would be paid the applicable LMP nodal real-time price for any scheduled energy that it does not take at its bid receipt point in real time.

282. The Independent Transmission Provider would post prices and other market information and settle the markets promptly to provide market participants with reliable information regarding their market transactions.

283. In certain instances, a generator may alleviate a voltage or stability constraint by producing real power and/or reactive power at its location. By alleviating the constraint, the transfer capability of the grid may be increased, thereby allowing a greater amount of lower-cost energy to be transmitted to an area with higher energy prices. For example, the transmission capability to import power into a load pocket may initially be limited to 1000 MW due to a voltage or stability constraint, even though the thermal limit is 1500 MW. However, production of an additional 100 MW of real power and/or an additional amount of reactive power within the load pocket could increase import capability into the load pocket by 50 MW, to 1050 MW. We seek comment on whether generators who provide such real or reactive power should receive additional compensation (in addition to the locational market price for energy and the applicable compensation for reactive

power) for the additional transfer capability that they create, to provide incentives to produce energy that increases transfer capability. For example, should such generators be given the Congestion Revenue Rights with the additional transfer capability that they create? In certain circumstances, a generator must reduce its production of real power in order to increase its production of reactive power. In these circumstances, should the generator be compensated for the opportunity cost of its reduced profits from selling real power? Should the generator be paid the higher of its opportunity costs or the market congestion value of the additional transfer capability created? How should locational market power concerns be addressed in these circumstances?

d. Day-Ahead Ancillary Service Markets

(1) General Features

284. Order No. 888 identifies six ancillary services, two of which may only be provided by the Independent Transmission Provider and four of which must be offered by, but need not be obtained from the Independent Transmission Provider. The four ancillary services that must be offered by, but need not be obtained from the Independent Transmission Provider, include:¹⁴⁹

- (1) Regulation and frequency response

¹⁴⁹These four ancillary services are in addition to two other ancillary services, (1) Scheduling, System Control and Dispatch Services and (2) Reactive Supply and Voltage Control. We seek comment on treating Scheduling, System Control and Dispatch Services as a basic cost of providing transmission service instead of as an ancillary service.

- (2) Energy imbalance
- (3) Operating reserve - spinning
- (4) Operating reserve - supplemental

Pursuant to the requirements of Order No. 888, transmission customers are assigned the responsibility for these ancillary services. Customers may meet their responsibility through self-supply, by procuring these ancillary services from a third party, or by acquiring them from the Independent Transmission Provider.

285. As discussed earlier, imbalance energy would be provided through the day-ahead and real-time energy markets. For the remaining three ancillary services (regulation and both operating reserves), we propose to require that the Independent Transmission Providers operate bid-based markets open to all potential suppliers so that Independent Transmission Providers can procure these ancillary services from the lowest cost suppliers. Different regional reliability authorities may establish different requirements for operating reserve - supplemental. For example, the four jurisdictional operating ISOs procure resources for the ancillary service operating reserve - supplemental (which are usually generation resources that are not synchronized with the grid or demand-side resources that can curtail use), with varying response times. Each ISO procures a portion of their necessary operating reserve - supplemental requirement with reserves that can respond within 10 minutes of a dispatch request, as well as slower-responding reserves at 30 minutes (New York ISO and ISO-New England) and 60 minutes (California). Since different regional reliability authorities have established different response times for

operating reserve - supplemental, we do not propose a standard set of markets for operating reserve - supplemental. However, we propose to require that each Independent Transmission Provider operate separate markets for each type of operating reserve - supplemental that it procures.

286. Location-specific reserve targets may be required in some areas due to persistent and significant congestion. The Independent Transmission Provider would identify and establish these targets consistent with any reliability rules.

(2) Bidding and Scheduling Rules

287. Each day, the Independent Transmission Provider would determine the total amount of each of the ancillary services that will be required for each hour of the following day. Customers that wish to meet their ancillary service requirement through self-supply or procurement through a third party would be required to provide the Independent Transmission Provider with the necessary information about the generation capacity or demand-side resource that would be providing the ancillary services (as is currently required under the existing pro forma tariff).

288. To procure the remaining amount of ancillary services, the Independent Transmission Provider would accept bids for regulation and the types of operating reserves for each hour of the following day. A participant desiring to sell regulation or operating reserves would submit a bid in a standardized form specified by the Independent Transmission Provider. Bids could be offered to provide ancillary services from generation capacity or any demand-side resource that meets the technical

requirements of the ancillary service. Participants could offer the same capacity in more than one ancillary service market, as well as in the energy market.

289. Each bid would indicate the type of ancillary service, the amount of generating capacity (MW) offered for sale, the receipt point of the resource and the time period. The bid would also include an availability bid indicating the minimum price per MW (which could be either a positive amount or zero) required to provide the ancillary service. The availability bid would allow the bidder to ensure that it would not be selected to provide the ancillary service unless the ancillary service price is high enough to cover out-of-pocket costs, such as the costs of keeping a crew at its facility for the following day. The bid would also include the various components that would be submitted to provide energy into the energy market. These components include an energy bid, indicating the minimum price per MWh required to produce energy. Other bid components would include price-bids for start-up and no-load, as well as technical constraints, such as minimum load, ramp rates, minimum run time and minimum down time. By providing one ancillary service, a bidder may forgo profits from sales in other markets, and these forgone profits are an opportunity cost of providing ancillary services. As explained in the following section, the Independent Transmission Provider will consider the opportunity cost associated with forgone sales in other markets operated by the Independent Transmission Provider. Opportunity costs from forgone sales in markets not operated by the Independent Transmission Provider could be included in the bidder's availability bid.

290. The Independent Transmission Provider would consider all bids to sell ancillary services, in conjunction with bids submitted in its day-ahead markets for energy and transmission service. As noted earlier, based on all submitted bids, the Independent Transmission Provider would maximize the economic value (as reflected in the bids) of the accepted bids, i.e., accept the bids with the overall lowest cost. Thus, for generation capacity and demand-side resource that bid into more than one market, the Independent Transmission Provider would schedule the generation capacity or demand-side resource into the market where it is most efficient (unless it is not efficient to schedule the generation capacity or demand-side resource in any market).¹⁵⁰ This should yield the overall lowest cost for procuring energy, regulation and operating reserves.

(3) Price Determination and Settlement

291. Based on the accepted bids included in the day-ahead schedule, the Independent Transmission Provider would establish day-ahead prices for each of the ancillary services procured in the bid-based markets for each hour. In regions with separate locational ancillary service requirements, the Independent Transmission Provider would establish separate hourly locational ancillary services prices.

¹⁵⁰Because of the way that prices would be established in each market, the market into which each bidder of generation capacity or demand-side resource is scheduled would also be the market that is the most profitable for the bidder. That is because, as discussed in the following section, the prices in each market would reflect marginal opportunity costs of the bidders in that market. Thus, the price in each market would be high enough to allow each accepted bidder in that market to receive at least as much profit as it could have received in any other market operated by the Independent Transmission Provider that it is technically capable of participating in.

292. To promote an efficient market, the price for regulation and operating reserves services would equal the marginal cost of each service, which would equal the highest accepted total bid cost expressed in dollars per MW. The total bid cost of each generator is the sum of: (1) the generator's availability bid per MW and (2) the opportunity cost of forgoing sales in other markets operated by the Independent Transmission Provider, expressed on a per-MW basis.¹⁵¹

293. A generator or demand-side resource could be eligible to bid into more than one market operated by the Independent Transmission Provider. The opportunity costs paid to the supplier would be the forgone profit from the most profitable other market. For example, a generator that is capable of providing ancillary services could also sell into the transmission provider's day-ahead energy market, although it would incur additional variable energy costs to do so. Thus, the forgone profit from selling into the energy market (as reflected in the generator's bid) would be the difference between the energy price and the generator's energy bid. The opportunity cost of selling ancillary services would include this forgone energy profit.

294. The hourly price for one of these ancillary services in a given location would thus equal the sum of the opportunity cost and the availability bid in dollars per MW of the most expensive unit accepted to provide that type of ancillary service in that hour to that location. As noted above, a generator providing any ancillary service is also technically

¹⁵¹Because prices are determined hourly, an opportunity cost expressed in dollars per MWh converts to an equivalent dollar-per-MW basis.

capable of providing a slower response ancillary service. For example, a generator providing operating reserve - spinning could also provide operating reserve - supplemental. Thus the opportunity cost of providing operating reserves - spinning would be at least as high as the price of operating reserve - supplemental. As a result, the marginal cost (and thus, the price) of operating reserve - spinning would not be less than the price of operating reserve - supplemental in the same hour.

295. Although suppliers bid to provide these ancillary services in the day-ahead market, customers pay for them based on real-time load. Transmission customers would be assessed a pro rata share of the total ancillary service requirements for each of these three ancillary services in each hour, based on their real-time, load-ratio share. Ancillary service requirements generally depend more on real-time transactions than on day-ahead schedules. Assessing ancillary service requirements based on day-ahead schedules would provide an incentive for customers to understate their day-ahead schedules.

296. In Order No. 888, exports are not charged for these ancillary services. We ask for comments on whether they should be charged here.

297. Customers that want to self-provide or procure their own ancillary services would be required to notify the Independent Transmission Provider in the day-ahead scheduling process and identify the resources that would be used to provide these services.

Customers would be given credit for the amount of ancillary services that they self-provide or procure from third parties. Customers that self-provide or procure from third

parties more capacity than their requirements would be paid the applicable hourly ancillary service price for the excess if needed by the market.¹⁵²

2. Scheduling After the Close of the Day-Ahead Market

a. Replacement Reserves

298. The Independent Transmission Provider will use the day-ahead market to develop prices and a schedule for suppliers. The prices and schedules will be based on the bids submitted by buyers and sellers. However, the day-ahead schedule may be less than the forecasted load in real time and, if so, the Independent Transmission Provider would commit additional units to ensure that load can be met reliably in real time.

299. After the Independent Transmission Provider has established a day-ahead schedule and associated prices for energy, transmission service and ancillary services, it would make its own forecast of load within its market area for each hour of the following day. To the extent that its forecasted load exceeds the amount of energy scheduled to be delivered to load in the day-ahead schedule, the Independent Transmission Provider may need to procure additional reserves (called "replacement" reserves) from generators to make up the difference, but only to the extent necessary to ensure that sufficient generation will be available to meet load.

¹⁵²Since the customer's day-ahead schedule was based on its projected share of the ancillary service requirement, it may have provided more than its actual share in real time. Thus, the customer would be compensated for the additional amounts it provided.

300. To procure replacement reserves, the Independent Transmission Provider would accept bids from generators submitted for the day-ahead market. The Independent Transmission Provider would select generators to provide replacement reserves so as to minimize the costs of availability, start-up costs and no-load costs regardless of energy costs. This approach to procuring replacement reserves would provide an incentive for load to accurately bid its load in the day-ahead market since energy prices may be higher in the real-time market.

301. As discussed further in the next section, generators selected to provide replacement reserves would be included in the real-time energy bid stack along with other generators that submit bids into the real-time market to provide energy. Generators selected to provide replacement reserves would be paid the applicable real-time energy price for energy that they produce. If a generator's revenues received from selling real-time energy are less than its bids for availability, start-up, no-load and energy, the Independent Transmission Provider would pay the generator an additional payment (i.e., an "uplift" payment) for the shortfall. The revenue shortfall would be recovered pro rata from all loads that buy energy in real time that have not been scheduled in the day-ahead market. Thus, the costs would be allocated to the customers that benefitted from the replacement reserves – customers that took power in real time. This provides an incentive for load to accurately predict its requirements in the day-ahead market.

302. We propose to add a new Section G.2 to the pro forma tariff that would implement the foregoing procedures for scheduling and paying for reserves after the close of the day-ahead market.

b. Changes to Transmission Schedules

303. A market participant that has not scheduled transmission service in the day-ahead market but desires transmission service in real time must inform the Independent Transmission Provider within specific time deadlines before real time. Market participants may change their day-ahead transmission service schedule by informing the Independent Transmission Provider consistent with the time deadlines.

304. Participants that have informed the Independent Transmission Provider of their desired changes within the Independent Transmission Provider's lead times, and adhere to the requested changes in real time, would settle the changes in transmission service at the applicable real-time transmission usage prices, described more fully below. Participants with new or increased transmission service would be charged the applicable real-time transmission usage price between the applicable receipt and delivery points for the new or increased transmission service in the applicable hour. Conversely, participants that reduce transmission service in real time (compared to the day-ahead schedule) would be paid the applicable hourly real-time transmission usage price for the applicable receipt and delivery points, to compensate them for the additional transmission capacity they have made available in real time.

3. Design of the Real-Time Markets

305. Under Standard Market Design, the Independent Transmission Provider would be required to operate bid-based, security-constrained real-time markets for transmission service, energy, and certain ancillary services (i.e., regulation, operating reserve - spinning and operating reserve - supplemental).

a. Real-time Energy Markets

(1) General Features

306. Under the Standard Market Design, the Independent Transmission Provider would accept bids to buy and sell energy in each hour in the real-time energy market. The bids would be in the standardized form specified by the Independent Transmission Provider. Real time energy markets would be used to provide the imbalance energy service of Order No. 888 pro forma tariff and self provision would be allowed. However, loads could voluntarily enter into bilateral contracts with suppliers in advance to lock in a fixed price for energy.

(2) Bidding and Scheduling Rules

307. In general, bids would indicate an offer to depart in real time from the bidder's day-ahead schedule to purchase or sell energy (including a day-ahead schedule to purchase or sell 0 MWhs of energy). Real-time bids would be accepted from any market participant, including generators, load-serving entities, eligible retail buyers, marketers and other agents. Bids would indicate the increase or decrease (in MWhs) from the day-ahead schedule in the amount of energy to be sold or purchased in real time, and the location and the hour of the changed purchase or sale. Each participant bidding into the

real-time energy market would be allowed to include multi-part price bids similar to those allowed in the day-ahead energy market (this is a departure from the Working Paper).

308. The transactions in real time vary from those reflected in the day-ahead schedule due to a variety of factors, including changes in weather conditions and unexpected equipment outages. The Independent Transmission Provider may be informed in advance of some of the scheduling departures under the procedures described above; other departures may occur without warning.

309. As occurs today, an Independent Transmission Provider will have to adjust energy production and/or load at various locations in order to balance generation with load and manage congestion. Under Standard Market Design, the Independent Transmission Provider would make these adjustments by calling upon participants that have submitted bids into the real-time energy market, as well as participants that have been selected to provide spinning, supplemental, and replacement reserves. The Independent Transmission Provider would issue dispatch instructions to bidders so as to balance generation and load, and efficiently manage congestion of demand and supply.

(3) Price Determination and Settlement

310. The Independent Transmission Provider would determine energy prices in the real-time energy market for each node for each 5-minute period or other subhourly period where a 5-minute determination is not technically achievable. Each price would reflect the marginal cost (as reflected in the real-time supply and demand bids) of producing energy and delivering it to the node in that period. The Independent Transmission

Provider would post prices and other market information and settle the markets promptly to give market participants reliable information regarding their market transactions.

311. To promote efficient participant decisions regarding real-time transactions, we propose that all departures in real time from the day-ahead schedule be settled through the real-time market at the applicable price (as is done today in many markets). Nodal pricing would be used for both buyers and sellers in the real-time market.

312. There are several aspects of the design of the real-time energy market where we seek additional comments.

Ex Post versus Ex Ante Prices

313. This Section discusses how to determine real-time energy prices. The options are to set the prices using near real-time estimates (ex ante), or base the price on the price of the actual marginal resource clearing the market in real time (ex post). Immediately in advance of each upcoming 5-minute period, the Independent Transmission Provider would announce the real-time energy prices that it estimates will clear the market and match generation with load during that upcoming period (based on the real-time bids submitted by market participants). The Independent Transmission Provider could settle all departures in real-time from the day-ahead schedule using these prices announced in advance. Such an ex ante pricing policy would provide price certainty and thereby encourage buyers and sellers that have not submitted bids to adjust their transactions in response to the announced price.

314. Alternatively, an ex post pricing policy could be used as an incentive for suppliers to follow dispatch instructions. Some bidders may not respond to the announced prices in the way suggested in their bids. For example, a supplier stating in its bid that it would increase its output by 50 MWh for each price increase of \$5/MWh may in fact increase its output by less than 50 MWh in response to such a price increase. By settling at the ex ante price, the generator would be paid the higher price despite the fact that it did not increase its output as it had promised in its bid. An ex post pricing rule might help to encourage bidders to respond in real time in a way consistent with their bids.

Specifically, the price used to settle real-time deviations from day-ahead schedules could be the price-bid associated with the energy observed ex post to be produced by the marginal supplier in the 5-minute period (but not higher than the advisory price announced ex ante). Such an ex post price rule would encourage suppliers to supply the full amount of energy promised in their bids.

315. We propose to adopt the ex post rule because it creates incentives for bidders to act consistent with their bids. We seek comment on the choice between ex post and ex ante pricing.

Other Charges for Uninstructed Deviations from Schedules

316. We seek comment on whether market participants should face additional charges for “uninstructed” deviations in real time from their schedules, i.e., for producing or taking a different amount of energy in real time than was scheduled without permission or direction from the Independent Transmission Provider. Uninstructed deviations from

schedules may increase the amount of regulation service or other ancillary services that the Independent Transmission Provider must procure, in order to reliably balance load and generation. If so, it would be appropriate to recover the costs of these services through a charge. We seek comment on whether the increased costs of regulation service or ancillary services should be allocated to the entities (buyers and sellers) that had uninstructed deviations from their schedules since the costs were incurred to serve these entities. Uninstructed deviations may also require the use of scarce ramping capability within the Independent Transmission Provider's market area. If ramping capability were used, it may be appropriate to charge for that use. We seek comment on whether and how to establish market prices for ramping capability. Finally, in extreme cases large uninstructed deviations can threaten reliability of service. To discourage this type of conduct a penalty provision may be appropriate.¹⁵³ We seek comment on whether the SMD Tariff should include penalty provisions for uninstructed deviations that threaten system reliability and how such penalty provisions should be structured.

What Bids Should be Eligible to Set the Energy Price

317. Strictly speaking, the marginal cost of meeting a small increment of load would be based on the bids of suppliers whose output can be increased, or buyers whose load can be decreased, from their scheduled level in the hour by as little as 1 MW. Thus, for example, the marginal cost of supplying load in an hour would not be based on the bid of

¹⁵³ This penalty would be in addition to any penalties incurred for violating curtailment orders.

any generator that is operating in the hour solely because of a minimum run constraint, because changes in load would not change the output of the generator.¹⁵⁴

318. However, we are concerned that by excluding generators whose output is adjustable in increments greater than 1 MW, on an hourly basis, from setting the energy price may not promote efficient results.¹⁵⁵ These potential inefficient results are more likely to occur in the real-time market than in the day-ahead market.¹⁵⁶ Therefore, we propose to allow generators whose output is adjustable on an hourly basis, but only in increments greater than 1 MW, to be eligible to set the energy price in the Real-Time Market if two conditions are met. First, the generator's output must be needed to meet

¹⁵⁴Also, a generator that is operating at its low operating limit would not be able to set the market-clearing price.

¹⁵⁵When such "lumpy" generators are needed to meet incremental load, it may be necessary to reduce the output of cheaper but more flexible generators (*i.e.*, generators whose output can be adjusted in 1 MW increments). For example, to meet a 30 MW increase in load, the cheapest available generator (with a bid of \$80/MWh) may be a combustion turbine with a capacity of 50 MW that can produce only at its maximum capacity. By operating the combustion turbine at 50 MW, the output of a cheaper flexible generator (with a bid of \$60/MWh) would need to be reduced by 20 MW in order to match the 30 MW increase in load with the net increase in generated output. Once the flexible \$60 generator is backed down, incremental load would be met with output from the flexible generator, so the marginal cost of meeting load would be \$60. However, it would not be efficient to meet the additional load unless the load valued electricity at more than \$80, the cost of the combustion turbine.

¹⁵⁶In the real-time market, some market participants that have not submitted bids may nevertheless adjust their production or consumption. Thus, the rules for setting energy prices in the real-time market should consider these possible effects on market participants that have not submitted bids. By contrast, day-ahead schedules are based only on bids and self-schedules submitted to the Independent Transmission Provider, so day-ahead prices cannot result in any unexpected changes in the day-ahead schedule.

load in the hour. That is, in the absence of the generator's output, either load could not be fully met or a more expensive generator would be needed to fully meet load. Second, the reason that the generator is operating must not be a minimum run time constraint. We also propose that any cheaper generators that are directed to reduce their output would be paid their opportunity costs (i.e., the difference between the applicable energy price and their energy bids) for the amount of the output reduction. With this payment, the generator is compensated for the legitimate opportunity cost of following the Independent Transmission Provider's instructions.¹⁵⁷

319. We seek comment on whether such lumpy generators should also be eligible to set the energy price in the day-ahead market. Although allowing these lumpy generators to set the energy price may have more direct benefit in the real-time market, we are concerned about potential negative ramifications from establishing different pricing rules for the day-ahead and real-time markets.

b. Real-Time Ancillary Services Markets

320. As discussed earlier, Order No. 888 requires transmission providers to offer to provide to transmission customers energy imbalance service, regulation and frequency response, operating reserve - spinning and operating reserve - supplemental. Under Standard Market Design, energy imbalance service would be provided through the transmission provider's real-time energy market. The Independent Transmission Provider

¹⁵⁷These payments would be recovered through an uplift charge to loads that purchase from the Independent Transmission Provider's markets.

would procure its expected requirements for the remaining three ancillary services through day-ahead ancillary service markets discussed above.

321. We propose that the Independent Transmission Provider operate a real-time ancillary services market to accommodate adjustments in the supply of ancillary services from the day-ahead schedule. In real time, there may be entities that can provide ancillary services more efficiently than those that were scheduled in the day-ahead market. The real-time market would permit such efficient substitutions. Higher-cost suppliers scheduled in the day-ahead market would buy back their offer to provide ancillary services at the applicable real-time price, and other, lower-cost entities would be paid the real-time price to take over the supply of ancillary services. In addition, the Independent Transmission Provider may need an amount of ancillary services that differs from the amounts procured in the day-ahead market, for several reasons. For example, the requirements expected in the day-ahead market may differ from actual, real-time requirements, or participants scheduled to provide ancillary services may experience outages in real time. Under Standard Market Design, the Independent Transmission Provider would procure any additional ancillary services needed in real time through the real-time ancillary service markets that it operates.

322. In the real-time market, the Independent Transmission Provider would accept bids for each ancillary service. As in the day-ahead market, a participant could offer the same capacity in more than one ancillary service market. The real-time bids would contain the same types of information as those submitted into the day-ahead ancillary service

markets, with one exception – we propose to exclude availability bids for spinning reserves and supplemental reserves in real time. The types of costs reflected in the availability bid to ensure that the supplier will be available to provide these reserves are incurred in the day-ahead time frame, not in real time.¹⁵⁸ There do not appear to be any incremental costs associated with providing these ancillary services in real time, other than the opportunity costs of forgoing sales in another market operated by the Independent Transmission Provider, and these opportunity costs would be reflected in the way that ancillary service prices are determined.¹⁵⁹

323. The Independent Transmission Provider would consider all bids to sell ancillary services in real time and select those bids that minimize the overall cost of procuring additional ancillary services required in real time.

324. Based on the bids accepted in the real-time market, the Independent Transmission Provider would establish real-time ancillary service prices for each hour that reflect the marginal cost of each service. All participants supplying a given type of ancillary service in a given hour in real time (and to a given location, if there are locational ancillary service requirements) would be paid the applicable market clearing price.

¹⁵⁸For example, the supplier may need to commit in advance to pay workers to staff its facility. However, the supplier would be able to offer to supply spinning reserves and supplemental reserves in real time if its workers were already staffing its facility, so in real time the supplier would not incur incremental costs to provide ancillary services.

¹⁵⁹Providing regulation service, however, would typically impose incremental out-of-pocket costs on the supplier, due to the additional wear and tear on equipment associated with frequent adjustments in output that regulation suppliers must make.

325. Transmission customers that have not self-supplied or procured through third parties their full assigned ancillary service requirement would be assessed a pro rata share of the costs incurred by the Independent Transmission Provider for procuring ancillary services in real time.

4. Market Rules for Shortages or Emergencies

326. We believe the market rules discussed above in combination with the market mitigation measures and the resource adequacy requirement will result in an efficient system for matching supply and demand under most operating conditions. However, we recognize that when emergency situations do occur, changes may be needed to the market rules to comply with reliability requirements. In the event of a capacity shortage or emergency, local reliability rules and procedures (which typically combine NERC, regional reliability council and system operator guidelines) prescribe a series of actions that the system operator takes to maintain reliability. For example, procurement of reserves is reduced, typically in order of reserve quality (that is, supplemental reserve quantities are reduced before spinning reserve quantities). The system may be re-dispatched to adjust the location and responsiveness of remaining reserves. System operators have also traditionally called on emergency supplies from neighboring systems (in the past, these emergency purchases have taken place at pre-defined prices; increasingly, they are being made at market prices). Finally, steps are taken for voluntary and involuntary load-shedding. States typically approve in advance the retail curtailment plans of utilities.

327. In the markets proposed in the SMD Tariff, we envision that with more extensive demand-side participation, the potential for these types of capacity shortage or emergency situations will substantially diminish. However, system emergencies may occur. The existing pro forma tariff gives transmission providers the authority to curtail transmission service and take any other preventive action necessary to preserve system reliability. The SMD Tariff would continue to grant the Independent Transmission Provider this same authority. However, the actions taken to ensure system reliability can affect prices in the energy and ancillary service markets. Market participants should be aware of how these actions will affect pricing in the markets operated by the Independent Transmission Provider. To that end, the SMD Tariff requires Independent Transmission Providers to file proposals with the Commission regarding the implications for market pricing of each reliability procedure. These proposals would need to be consistent with the resource adequacy mechanisms discussed below, but could vary to reflect regional differences in reliability requirements. We seek comments on what, if any, more specific requirements should be included in the Final Rule.

G. Other Changes to Remove Undue Discrimination and Improve the Efficiency of the Markets under Standard Market Design

328. The existing pro forma tariff was constructed primarily to apply to vertically integrated public utilities. It was the first step toward competitive electric power markets since it allowed alternate suppliers to access loads through an open access transmission tariff. It sought to replicate the terms and conditions under which the host public utility

served its own loads. It also was the first step in separating the generation and transmission arms of a public utility.

329. But more changes are needed to further the development of regional competitive wholesale electric markets and assure comparable and non-discriminatory treatment of all market participants. Accordingly, the following revisions must be made to the pro forma tariff to change the market rules in ways that will improve the efficiency of wholesale electric markets.

1. Capacity Benefit Margin

330. Capacity Benefit Margin is the set-aside of transmission capability by a transmission provider to ensure the ability to import external resources to meet generation reliability requirements or in case of a generation capacity deficiency. During the Commission's outreach process, many commenters asserted that Capacity Benefit Margin ties up valuable transfer capability without a specific reservation and payment by the customers who receive the benefit of the set-aside. The subsidy occurs because, while part of the transfer capability is withheld from the market as Capacity Benefit Margin, the wholesale transmission customers using the system pay the entire transmission cost (including that of the Capacity Benefit Margin) through their transmission charges, thus subsidizing the Capacity Benefit Margin beneficiaries. The use of a Capacity Benefit Margin has also been regularly challenged on the grounds that the host transmission provider is withholding transfer capability under the guise of Capacity Benefit Margin in order to thwart competition.

331. We propose to standardize the treatment of Capacity Benefit Margin to ensure that (1) only customers benefitting from it pay for it, and (2) transfer capability needed to access resources on a neighboring system is treated consistent with all other portions of the transmission grid. Thus, an Independent Transmission Provider itself would not be permitted to set aside transfer capability for generation reliability reasons. Rather, a load-serving entity wanting access to resources on a neighboring transmission system to meet its resource adequacy requirement should instead acquire Congestion Revenue Rights from the interface to its load to ensure that access. This will free up transfer capability now unavailable to wholesale transmission customers and prevent cross-subsidization of transmission customers that serve load within the Independent Transmission Provider's service area by point-to-point transmission system users.¹⁶⁰

332. This prohibition of the generic set-aside of transfer capability by the Independent Transmission Provider for generation reliability reasons does not apply to an Independent Transmission Provider's responsibility to set aside transfer capability to ensure transmission reliability (e.g., to ensure that a line can take up the power flows it must absorb if a parallel line should go out of service or other uncertainties in system conditions arise). Such a set-aside is called Transmission Reliability Margin and must be consistent with good utility practice and should not be implemented in a way that favors

¹⁶⁰To the extent that an Independent Transmission Provider's load ratio share access charge calculation does not pick up this reservation, the amount of interface capability can be imputed and added to the customer's peak day amount.

particular transmission customers (e.g., by release of the set-aside capability for use by native load).

2. Regional and Independent Calculation of Available Transfer Capability, Performance of Facilities Studies and OASIS

333. The Commission has found specific instances of abuse by transmission providers regarding the Available Transfer Capability calculation process and delays in the completion of transmission facilities studies.¹⁶¹ There are obvious incentives for a vertically integrated transmission provider to favor its own generation by delaying facilities studies or manipulating the Available Transfer Capability calculations or postings on its OASIS. Under Standard Market Design, calculations of transmission capability and the performance of facilities studies for transmission expansions must be performed by an independent entity to reduce the opportunity for preferential treatment by the transmission provider.

334. More broadly, the SMD Tariff must recognize the regional nature of today's energy markets. Transmission capabilities must be calculated not for a single utility's service territory, but regionally to encompass existing trading patterns and power flows, particularly parallel path flows on neighboring systems. All transmission providers that are not part of a Commission-approved RTO must contract with an independent entity to perform transmission capability calculations on a regional basis. Likewise, we propose to require a common OASIS for the region.

¹⁶¹See Section III and Appendix C.

3. Regional Planning Process

335. Competitive and reliable regional power markets require adequate transmission infrastructure to allow geographically broad supply choices and minimize the complications created by loop flow. The recent DOE National Grid Study documented the problems resulting from recent under-investment in transmission infrastructure and identified a number of causes. Among the causes were the lack of regional planning and coordination of transmission needs and siting issues.

336. Transmission planning and expansion have generally been performed for a single control area rather than on a regional basis. This yields sub-optimal solutions, as individual transmission providers consider power flows across a limited area and do not adequately consider entire markets. Parallel path flows that occur on neighboring systems may make the construction of specific facilities less cost-effective than a regional solution. This effect can be properly considered by performing transmission planning and expansion on a regional basis. Moreover, facilities that, if constructed in one system would be the optimal solution for a neighboring system, might never be considered under a single control area-based planning model.

337. Implementation of Standard Market Design will only increase the importance of examining these issues on a regional basis. More open and transparent markets will enable customers to purchase from distant suppliers, increasing use of the grid.

Locational marginal prices that result from the spot markets operated by an Independent Transmission Provider would signal to all market participants the value of additional

supply and demand response at particular locations. Based on these prices over time, market participants will be able to decide whether additional investment – in transmission or generation facilities or demand response – is warranted. The ability of individual market participants to see the economics of possible solutions and make market-driven decisions concerning the addition of infrastructure is the fundamental mechanism that induces efficient investment under Standard Market Design. The policy relies primarily on a "ground-up" planning process that encourages construction by private companies yet also recognizes the need for of a regional evaluation process for loop flow effects and cost-effectiveness. It is neutral with respect to the type of investment market participants may make in response to these price signals. However, due to loop flow, all system modifications would need to be coordinated through a regional process and would have to meet any criteria needed to maintain reliability and stability, and assure that existing customer rights are not impaired.

338. Given the need for transmission investment in much of the country and the time it will take to implement Standard Market Design and for investors to observe and respond to price signals, we propose that a regional planning process be instituted within six months of the effective date of the Final Rule. This process should be designed to identify beneficial transmission needed for both reliability and economic reasons to support regional markets and reduce the effects of generation concentration. The regional planning process should allow the market to respond to those identified needs.

339. A critical piece of the transmission planning process is state-level siting decisions.

We note a recent National Governors' Association report that recommends Multi-State Entities to facilitate regional transmission planning decisions.¹⁶² Multi-State Entities, along with an open regional planning process, would preserve the states' role in siting decisions, while promoting regional solutions. A Multi-State Entity could be an important component of the regional planning process.

340. Certain areas of the country and organizations already have proposals or processes to consider regional planning or development of regional markets. Building off of these existing efforts will help facilitate the development of a regional planning process in the near term. We emphasize that a planning area need not coincide with the geographic area of a Commission-approved RTO or Independent Transmission Provider required by this rule. Also, because of the interrelationships between Canadian and US energy markets, we encourage participation by Canadian entities and provincial authorities in the regional planning process.

341. Current processes such as the Committee on Regional Electric Power Cooperation in the West provide for state and provincial advice in the planning across the entire Western grid. Therefore, we propose to use the area covered by Western Electricity

¹⁶²See Interstate Strategies for Transmission Planning and Expansion, National Governors' Association, posted on July 18, 2002, available in http://www.nga.org/center/divisions/1,1188,C_ISSUE_BRIEF^D_4110,0.html.

Coordinating Council (WECC) that encompasses the geographic area covered by the Western Grid for regional planning purposes.

342. In the Eastern Interconnection there have been several efforts at developing regional wholesale electricity markets that we propose to build on for the regional planning process. PJM and MISO developed a Memorandum of Cooperation dated May 9, 2002 that commits to develop a joint and common wholesale electric market for PJM, MISO, and SPP. Consequently, we propose that the area covered by these organizations would also be a regional planning area.

343. Similarly, New York ISO and ISO-New England are currently pursuing discussions on the merger of these two organizations into a Northeast RTO. Both are also members of the Northeast Power Coordinating Council which has recently conducted studies of transmission needs in the region.¹⁶³ We propose to build on these efforts and use the area covered by these organizations as a planning area.

344. Finally, we recognize that there has been ongoing discussion development of regional markets in the Southeast. SETrans Regional Transmission Organization proposes to encompass a broad area in the Southeast. The Tennessee Valley Authority (TVA) has signed a Memorandum of Understanding with Southern Companies and Entergy, two sponsors of SETrans, to work together to develop coordination agreements. Additionally, the SETrans and GridSouth Transco, LLC parties signed a Memorandum of

¹⁶³Northeast Power Coordinating Council Collaborative Planning Initiative Phase I issued March 13, 2002.

Understanding in January 2002 calling for similar regional coordination. Thus we propose to build on these efforts and propose a Southeast planning area composed of the Southeastern Electric Reliability Council and the Florida Reliability Coordinating Council.

345. We propose that all public utilities that own, control, or operate transmission facilities must participate in a regional planning process for the planning areas discussed above. We propose that this process start within six months after the effective date of the Final Rule and that the first regional transmission plan be completed within twelve months after the effective date of the Final Rule. Reliance on these existing regional efforts should facilitate the start-up of the regional planning process before Standard Market Design is implemented and all areas have Independent Transmission Providers operating transmission facilities.

346. After Standard Market Design is fully implemented, we believe the regional planning process will change as Independent Transmission Providers play a greater role in that process. There will still remain a significant need for a regional planning process to supplement private "ground up" investment decisions. The regional planning process is intended to supplement these private investment decisions, not supplant them. The regional planning process must provide a review of all proposed projects to assess whether the project would create loop flow issues that must be resolved on a regional basis. In addition, because of the externalities involved, there may be no private investment sponsor for some projects that would benefit the region. Private investment

decisions in response to prices may not result in adequate expansions for two reasons.

First, private parties may not be eligible to ask the state to exercise its eminent domain rights. Second, some needed and beneficial expansions may not create enough identifiable financial benefits to compensate private investors adequately, so those projects will not be built under a system that relies solely on private investment to expand the grid. A regional planning process can identify both the projects that would benefit the planning area and potential alternatives in a fair and unbiased manner. Additionally, a regional planning process, would evaluate the benefits of alternative proposals and provide an independent assessment of which projects are the most cost effective and/or have the least environmental impact.

347. To complement private investment initiatives, we propose that Independent Transmission Providers establish a mechanism for regional transmission planning and expansion guided by the following principles. First, the planning process should identify all expansion needs on the system, including both reliability and economic needs (e.g., to reduce congestion). The planning process should leave open the question of how and by whom those needs should be met, without favoring one solution (whether it is transmission, generation or demand response) over another. The planning process should be open to all industry segments. Additionally, all entities could propose projects. As long as the project did not make existing Congestion Revenue Rights infeasible due to loop flow problems, the entity would be free to complete the project as long as it is willing to assume any market or regulatory risk. However, to the extent the entity sought

to roll-in the costs of the facilities, the rate treatment should be reviewed through the planning process.

348. Second, an Independent Transmission Provider should have the responsibility to issue requests for proposals when the planning process determines that additional resources are needed to serve the regional market. Parties may respond with proposals to expand the grid, add generation (including distributed generation), or implement demand response.¹⁶⁴ The Independent Transmission Provider would approve transmission expansions that would be paid for by all customers only when planned private investments are judged to be inadequate to meet the reliability and market needs of the region. If the bidding process fails to produce a satisfactory outcome, such that the Independent Transmission Provider determines that additional facilities are needed, the affected transmission owner(s) would be required to expand or upgrade the transmission system.¹⁶⁵

349. Finally, the Independent Transmission Provider would act as a clearinghouse for proposed projects. It could identify separate projects that could be constructed at a lower cost if the projects were combined. Also, if there are alternative projects that have been

¹⁶⁴We recognize that the states have the ultimate authority over siting.

¹⁶⁵See existing pro forma tariff §§ 13.5 and 15.4 (transmission provider required to expand its transmission system if transmission customer agrees to compensate the transmission provider). This requirement extends to the transmission owners.

proposed, the Independent Transmission Provider could evaluate the relative advantages of the alternative projects.

350. This approach to regional planning and expansion is fully consistent with Standard Market Design's goal of inducing efficient investment by relying primarily on price signals and independently administered Congestion Revenue Rights. At the same time, it recognizes that private investment decisions may not be fully adequate in all cases because of eminent domain and the possibility that private benefits of investment could be significantly less than social benefits. The planning process would have a regional scope, permit direct competition among all types of investment, include all market participants equally, and minimize the need to rely on eminent domain and the support of captive customers. Because existing transmission owners are the transmission builder of last resort, it also respects the reality that not all states allow non-traditional utilities to build in their state or to obtain eminent domain, thus creating a legal barrier to entry.

4. Modular Software Design

351. Software and data issues have become an important part of the market design and changes to market design. On many occasions over the past several years, market designs and improvements have been delayed or even abandoned due to software constraints or software development costs. Software and data systems inherited from the old structure are often idiosyncratic, making changes and seams issues more difficult than they should be. Market participants often find software to be impenetrable "black boxes." Software development and modifications have become expensive and software "wheels" are being

reinvented. Consequently, the software used to implement the Standard Market Design's real-time and day-ahead markets will be a critical element in the feasibility and success of Standard Market Design.

352. The Standard Market Design software should have the following characteristics: transparency (the ability to understand what the software does), testability (the ability to understand and compare performance) and modularity (the ability to change software modules without changing other software). Transparency, modularity and testability help break down entry barriers and allow for competition in software development.

Modularity requires standard interfaces (well-defined data inputs and outputs and ease of access). Since we expect Standard Market Design to evolve over time and wholesale markets to grow, the underlying software must be able to accommodate change.

Scalability, security and robustness are desirable design features.

353. All market and operations software approximates the actual operation of the system. However, computational and feasibility issues are not well understood. Issues include performance, AC vs. DC models and consistency if both are used. Unit commitment models use different heuristics that were not important in the old vertical structure, but can be very important for new demand and supply entrants in a decentralized market. To instill confidence in the software, testing, validation and evaluation should be a part of an open process.

354. We propose to require that the software meet the characteristics set forth above and that the input and output data systems and other Electronic Data Interchange be

standardized in a common data model including a data dictionary (glossary and/or data definitions) and common network description. We seek comment on the following questions.

355. The Commission held a conference on July 18, 2002, to discuss the operational data and software needed to implement Standard Market Design and large regional wholesale markets, following an earlier conference on software issues. Among the topics discussed were market operational software capabilities, software standardization, ISO experiences with implementing software, cyber-security and the need to achieve some standardization within the electric market and grid operations software modules across vendors.

356. The conference established that for most applications, software does not appear to be a binding constraint on the size of RTOs or the implementation of Standard Market Design. Participants noted that the computational algorithms inside the models are continually improving, as is the speed of the processors used to solve the models, so it is reasonable to expect that software and associated hardware needs should keep pace with market span.

357. The Commission's goal is to assure that the best software is available for use in the nation's wholesale markets. This can best be attained by promoting competition among vendors, in a way that assures that no vendor comes to "own" a market niche or impose barriers to entry by new software companies with innovative analytical approaches.

358. Many vendors have particular areas of expertise and their software is often integrated with other software in complete software systems. We propose to encourage the development of "plug-and-play" software designs so that the best modules can be integrated into complete market operational systems for Independent Transmission Providers. To accomplish this we need to standardize data transfer between modules. Participants at the conference proposed two ways of accomplishing this – open systems and standardization. The open systems approach would leave it to each vendor to develop and publish the interface to the next module in the system. The standardization approach would define a set of minimum specific standard functions for each software module and specify the interfaces to be used between modules. We believe that the standardization approach is best suited to the close time frame needed for Standard Market Design implementation, and invite comment on the best process to develop these standards – should we use the evolving NAESB process or forums set up by the Electric Power Research Institute for this purpose, or use another approach?

359. The discussion of a suite of benchmark problems to test software illustrated the importance of benchmarking to facilitate testing and comparison of candidate software with respect to solution outcomes and processing time. We therefore encourage the industry to develop such a suite of benchmark or test problems.

360. As a follow-up to the July 18, 2002 Standard Market Design software conference, the Commission will hold another conference on these topics on October 3, 2002. This conference will focus particularly and in detail on what process or body should be used to

set standards for data standardization for inputs and outputs to software modules; whether the standards already developed by the Ontario Independent Market Operator for this purpose might be applicable for United States markets;¹⁶⁶ and how to proceed with the development of test problems for evaluating and comparing software modules.

5. Transmission Facilities That Must be Under the Control of an Independent Transmission Provider

361. In a variety of public forums, including RTO conferences and comments to RTO proceedings, much uncertainty has been expressed concerning two questions: which facilities belong under the control of the RTO; and which customer-owned transmission facilities that are turned over to RTO control are entitled to a credit?¹⁶⁷ In some instances, the dispute centers on whether the facilities are integrated. Other disputes involve the voltage level at which a facility is determined to be transmission. Under this proposed rule, the question becomes which transmission facilities must be under the control or an Independent Transmission Provider, be it an RTO or not.

a. Before Order No. 888

362. Before Order No. 888, much of the industry consisted of vertically integrated investor-owned utilities (IOUs) that, for the most part, provided a single service – bundled requirements power – to retail and wholesale customers alike. The classification

¹⁶⁶See <http://www.oeb.gov.on.ca/english/electronic_business_standards.htm> last visited July 30, 2002.

¹⁶⁷See, e.g., City of Vernon, California, 93 FERC ¶ 61,103 (2000), 94 FERC ¶ 61,344 and 61,148 (2001); 95 FERC ¶ 61,274 (2001); and 96 FERC ¶ 61,312 (2001).

of delivery facilities between transmission and distribution came up only in a ratemaking context. Because wholesale requirements customers purchased bulk power, they often did not require service over distribution facilities. Often, only a stepdown substation or a feeder line was involved. For those few stand-alone transmission services that an IOU might provide, the cost allocation issue was the same. The Commission approached this allocation issue by defining an integrated transmission grid as those facilities that operate in a single cohesive fashion to deliver bulk power and allocating wholesale (and stand-alone transmission customers) a proportional share of the embedded costs of those facilities on a rolled-in basis with postage stamp pricing.

363. Infrequently, the Commission would consider rate treatments premised on the distinction between transmission and subtransmission (high and low voltage transmission). If there were delivery facilities (transmission or distribution) that were not part of the integrated grid, but were used by a specific wholesale customer (e.g., radial tap line or stepdown substation), the Commission would allow the direct assignment of those facility costs in wholesale rates.

364. These issues were discussed at length in Commission cases in the 1970s when IOUs attempted to bifurcate the pricing (effectively pancaking) and thereby increase their wholesale revenues. Customers, on the other hand, wanted to classify facilities as transmission and thereby decrease their delivered energy charges by only paying one charge for these facilities. While the issue was often framed as a transmission/distribution issue, it was mostly a battle over utilities trying to pancake rates

(through charging a rolled-in rate plus a direct assignment charge) for transmission facilities or facilities that provided both transmission and distribution functions (dual-function facilities).

b. Order No. 888

365. Order No. 888 did not require a change in traditional rate treatments. However, since the Commission issued its open access rules, a number of utilities have proposed subclassifications of transmission, e.g., transmission and subtransmission. Protestors (generally transmission-dependent utilities) have argued that this rate treatment favors transmission users that are connected to the transmission system at higher voltages (i.e., the transmission owners' own generation) by reducing their rates for open access transmission service (because they pay only the high-voltage charge) and that reclassification is just another way to pancake rates and increase charges to low-voltage users. During the Commission's public outreach, commenters pointed to such splits as the pool transmission facilities (PTF)/non-pool transmission facilities in ISO New England as an example. This is not a consistent classification of pool transmission facilities and non-pool transmission facilities among transmission owners in New England. A generator located on a lower voltage portion of the ISO's grid must pay an additional non-PTF charge to access the New England market, but other, generators do not, putting the first generator at a competitive disadvantage.

366. The issue of transmission/distribution classification in Order No. 888 was in the context of unbundled retail transmission service and the Federal Power Act's legal

jurisdiction distinction between "transmission" facilities (subject to Commission jurisdiction) and "local distribution" facilities (subject to state or local jurisdiction). To determine what facilities would be under Commission jurisdiction for purposes of the Order No. 888 open access requirements and what facilities would remain subject to state jurisdiction for purposes of retail stranded cost adders or other retail regulatory purposes, the Commission developed a seven factor test to determine what facilities are transmission facilities and what facilities are local distribution facilities.¹⁶⁸ With respect to the seven factor test, the Commission also stated that it would defer to the state commission's findings as to what facilities constitute local distribution facilities if the state's determination was consistent with our comparability principles. In addition, dual purpose facilities, i.e., those used both for transmission or wholesale sales and for local distribution, would fall under the Commission's jurisdiction. To the extent use of particular facilities changed over time, the Commission would revisit these determinations. The Supreme Court upheld these determinations upon appellate review.¹⁶⁹

c. Test for Transmission Facilities

367. Order No. 888's seven factor test was designed to determine the local distribution component of an unbundled retail sale. The test did not exist prior to Order No. 888 and

¹⁶⁸ Order 888 at 31,771.

¹⁶⁹ New York v. FERC, 122 S. Ct. 1012.

in fact was created to do something the Commission had never done before – identify local (retail) distribution facilities. Thus, the test identifies all facilities that are not local distribution facilities. We propose that this is the appropriate starting point for determining which facilities belong under the control of an Independent Transmission Provider. To the extent that a transmission owner or Independent Transmission Provider believes that certain facilities should not be under the Independent Transmission Provider's control, the Independent Transmission Provider may request an exception to this presumptive determination.

368. This proposed test focuses on the presumption that, if a facility is transmission, it belongs under the control of the Independent Transmission Provider. Thus, once a determination is made with the seven factor test, there would be no need for an additional review under the Commission's previous integrated facilities test. In MidAmerican Energy Company,¹⁷⁰ the Commission explained that the Commission's determination of which facilities are transmission is fluid and dependent on actual the use of the facilities:

Although we are accepting the state commissions' classification, we reiterate our finding in Order No. 888 that to the extent that any facilities, regardless of their original nominal classification, in fact, prove to be used by public utilities to provide transmission service in interstate commerce in order to deliver power and energy to wholesale purchasers, such facilities become subject to this Commission's jurisdiction and review.¹⁷¹ In addition, the rates,

¹⁷⁰90 FERC ¶ 61,105 (2000).

¹⁷¹In Order No. 888, the Commission explained that "a public utility's facilities
(continued...)

terms and conditions of all wholesale and unbundled retail transmission service provided by public utilities in interstate commerce are subject to this Commission's jurisdiction and review.¹⁷²

Further, our deference in this proceeding does not affect the Commission's separate determination of what facilities must be under the operational control of RTOs, including ISOs and Transcos.¹⁷³ The Commission will make this latter determination, taking into account the seven factors formulated for purposes of determining jurisdiction as set forth in Order No. 888,¹⁷⁴ the ISO principles set forth in Order No. 888,¹⁷⁵ and the principles set forth in the RTO Final Rule.¹⁷⁶

¹⁷¹(...continued)

used to deliver electric energy to a wholesale purchaser, whether labeled "transmission," "distribution," or "local distribution," are subject to the Commission's exclusive jurisdiction under sections 205 and 206 of the FPA." Order No. 888 at 31,969; accord Nevada Power Company, 88 FERC ¶ 61,234 at 61,768 (1999).

¹⁷²Transmission service in interstate commerce by public utilities, including the rates, terms and conditions for such service, remains within this Commission's exclusive jurisdiction. 16 U.S.C. 824, 824d, 824e (1994). See generally Order No. 888-A at 30,339-41.

¹⁷³Which facilities will or will not be under an RTO's operational control also does not predetermine transmission pricing, cost allocation, or rate design determinations at either a state commission or at this Commission.

¹⁷⁴Order No. 888 at 31,771.

¹⁷⁵Order No. 888 at 31,730-32.

¹⁷⁶Regional Transmission Organizations, Order No. 2000, FERC Stats. & Regs. ¶ (1999) (RTO Final Rule).

We note that the determination of which facilities are under the operational control of the Independent Transmission Provider does not dictate transmission pricing.¹⁷⁷

369. We request comment whether, either in addition to or in lieu of the seven factor test, the Commission should use a bright line voltage test (e.g., 69 kV) to determine which facilities are placed under the control of the Independent Transmission Provider. If so, we seek comment on the bright line, whether we should allow regional variation, and how transmission facilities that are not placed under the control of the Independent Transmission Provider's tariff are treated with respect to open access and rates.

H. Transition to Single Transmission Tariff

370. This section discusses the transition process that will be used to move from the existing pro forma tariff to the SMD Tariff. First, we discuss the provisions of the revised tariff that remain the same as those in the existing pro forma tariff, but may change based on the comments received in response to our questions. Second, we discuss the provisions we propose to change. When Standard Market Design is implemented, the revised tariff would apply to nearly all transmission services on the system. All customers would receive the same quality and quantity of service they currently receive. Customers currently taking transmission service under an open access transmission tariff

¹⁷⁷As noted in MidAmerican, present ISO agreements obligate transmission owners to provide access over facilities that are not under the control of the ISO if those facilities are needed to provide wholesale transmission service regardless of ownership or whether those facilities are labeled transmission, distribution (i.e., distribution facilities other than local distribution), or local distribution. The same holds for Independent Transmission Providers.

would continue to do so, but now would be served under the new Network Access Service under a revised open access transmission tariff. Bundled retail customers would continue to receive service from their existing load-serving entity; however, the load-serving entity would be required to take service under the new Network Access Service pro forma tariff in order to serve those retail customers. Similarly, while wholesale customers with pre-Order No. 888 contracts would be given the opportunity to convert to the new transmission service under a revised open access transmission tariff, if they choose not to do so, the transmission owner that provides service under the pre-888 contract would be required to take service under the new Network Access Service pro forma tariff in order to meet its contractual obligations to serve those customers.

371. Standard Market Design is intended to cure undue discrimination, more efficiently use the transmission grid and give customers additional options. To help ensure that the transition process satisfies these objectives, the proposed rule would allow certain regional flexibility in the implementation process to the SMD Tariff. In particular, the regions would have flexibility in converting the rights of existing customers to Congestion Revenue Rights or auction revenues under the new tariff. Also, the regions would have flexibility in establishing the rate design for the new Independent Transmission Providers. It is anticipated that the state representatives, through the Regional State Advisory Committees discussed in Section IV.K., will play an active role in these regional decisions.

1. Treatment of Customers under Existing Wholesale Contracts

372. When the Commission issued Order No. 888 it faced the issue of what to do with existing contracts. The Commission decided that it would not generically abrogate existing requirements and transmission contracts, but that under all post-Order No. 888 contracts were to conform to the Order No. 888 pro forma tariff.

373. Similarly, we propose not to abrogate existing pre-Order No. 888 contracts. On a nationwide basis, these contracts should represent a relatively small portion of the total load and should be able to be accommodated within the Standard Market Design.¹⁷⁸ The customers with these contracts will be able to convert these existing contracts, consistent with their contract terms, to the new Network Access Service upon implementation of Standard Market Design. However, as discussed below, if customers choose not to convert to the new service, the transmission owner would be required to take service under the new tariff in order to meet its contractual obligations to serve the pre-Order No. 888 contract customers.

374. If pre-Order No. 888 contracts remain in effect, the contracting transmission owner would be required to take service from the Independent Transmission Provider in order to serve its existing wholesale power or transmission contract. The Independent Transmission Provider will assess the transmission owner for all charges and payments for providing the transmission service. The transmission owner will receive the

¹⁷⁸It appears that these contracts would be less than 10 percent of total load on a nationwide basis based on data from Form No. 1 filings by public utilities for calendar year 2000.

allocation of initial Congestion Revenue Rights (or auction revenues associated with Congestion Revenue Rights) to provide protection against congestion costs for these existing contracts. If the ultimate transmission customer prefers having a direct allocation of these rights, it can convert the contract, subject to any contractual limitations, so that the customer directly receives service through a service agreement under the SMD Tariff and would take service directly from the Independent Transmission Provider.¹⁷⁹ We expect that the Congestion Revenue Rights or auction revenues for Congestion Revenue Rights that the transmission owner will receive in association with these contracts will be sufficient to cover increased congestion costs that would result from having the transmission owner take service under the new tariff in order to serve its wholesale requirements customers. However, the transmission owner would have the right to make a filing pursuant to section 205 of the Federal Power Act to demonstrate that its revenue requirement should be adjusted to recover additional costs caused by implementation of this provision.

375. The Commission is concerned that pre-Order No. 888 contracts could permit the parties to extend a contract indefinitely through the use of roll-over or evergreen provisions in the contracts. The Commission seeks comment on whether it should limit the ability of the parties to extend these contracts past their initial term, or if that has passed the end of the next roll-over period and, if so, what limitations are appropriate.

¹⁷⁹To the extent that there are contractual limitations, the customer could seek modification of the contract through a filing with the Commission.

2. Allocation of Congestion Revenue Rights

376. The initial allocation of Congestion Revenue Rights is important to ensure that the implementation of Standard Market Design preserves the service rights of existing customers, provides access to all available capacity and minimizes cost shifts. We offer a process for this transition. First, the Independent Transmission Provider would compile a catalogue of all the existing long-term firm obligations for its transmission system that would still be in effect when Standard Market Design is implemented.¹⁸⁰ This would include firm Point-to-Point Transmission Service under an open access transmission tariff,¹⁸¹ firm transmission under pre-Order No. 888 contracts, designated resources for network transmission service pursuant to an open access transmission tariff, and bundled retail load (which is served under an implicit contract with the transmission owner). For firm Point-to-Point Transmission Service, the existing rights would be those specified in existing service agreements. For network transmission service and bundled retail transmission service, the existing rights would be limited to the designated resources in effect at the time, up to an amount equal to the customer's current peak load since this would replicate the service the customer is currently receiving. The Congestion Revenue

¹⁸⁰Network transmission contracts are not currently assignable because they do not consist of reservations from particular receipt points to delivery points in specific stated amounts. Therefore, some measure of historical usage on a point-to-point basis will have to be imputed to each network customer in order to assign Congestion Revenue Rights.

¹⁸¹Short-term firm contracts would expire before the implementation of Standard Market Design and would thus not be included in the catalogue.

Rights would go to the entity taking service under the Independent Transmission Provider's tariff. In general, these customers would not be granted an initial allocation based on additions for future load growth, but would have to secure those rights. However, there are instances where the vertically integrated transmission provider has identified load growth and limited the term (and rollover rights) of point-to-point transmission contracts. We seek comment as to whether and under what circumstances load growth should be accommodated in the direct allocation of Congestion Revenue Rights. The initial Congestion Revenue Rights would be receipt point-to-delivery point obligations.

377. Next, the catalogue of firm obligations would be subject to a simultaneous feasibility test.¹⁸² On some systems, it may not be possible to award Congestion Revenue Rights that are simultaneously feasible to all of the existing firm transmission customers on the system, because the system may be leveraging load diversity – different customers using the grid at different times – to meet the peak needs of all users. If those needs cannot all be met simultaneously, then not all customers can have annual Congestion Revenue Rights equal to their peak usage,¹⁸³ then the initial allocation of

¹⁸²Simultaneously feasibility means that power can be simultaneously transmitted from the receipt points to the delivery points specified in the Congestion Revenue Rights in a contingency-constrained dispatch. If this power flow does not cause overloads on the system (either pre- or post-contingency), then the power flow is simultaneously feasible.

¹⁸³Congestion Revenue Rights that give a holder different seasonal quantities could be an option in such a case.

Congestion Revenue Rights would be limited to the amount that is simultaneously feasible. The Congestion Revenue Rights could be allocated between customers on a pro rata basis or customers could be given the opportunity to change receipt points to achieve a simultaneously feasible result, or the Congestion Revenue Rights could be restricted to certain periods.¹⁸⁴

378. Either of two methods could ensure that current customers receive the value of their current contracts (actual or implicit) – direct assignment and an auction with a revenue assignment.¹⁸⁵ First, Congestion Revenue Rights could be directly assigned to the customers that currently have the receipt points and delivery points identified in their existing contracts (actual or implicit). Under this approach, a customer that currently has a firm point-to-point transmission contract for 100 MW from point A to point B would receive 100MW of Congestion Revenue Rights from point A to point B for the length of its contract. A network customer or a load-serving entity serving retail load that has identified a network resource for 100 MW of capacity would receive a Congestion Revenue Right for 100 MW from that receipt point to the customer's load.¹⁸⁶ The

¹⁸⁴If the simultaneous feasibility tests indicate there are additional Congestion Revenue Rights that could be offered, these Congestion Revenue Rights will be offered through an auction open to all customers.

¹⁸⁵For the sake of simplification, this discussion assumes that simultaneously feasible Congestion Revenue Rights could be issued to replicate current rights. If adjustments need to be made to ensure a simultaneously feasible result, the numbers may change, but the same basic methodology would be used for the conversion process.

¹⁸⁶In states that have retail competition, provisions would also be needed to ensure
(continued...)

delivery points would be defined as the customer's interface points with the Transmission Provider. For network contracts and implicit contract, it is likely that customers would continue service for the foreseeable future (without a contract termination date). Thus, we seek comment on what type of term should be used for purposes of the Congestion Revenue Rights allocation for these contracts.

379. Alternatively, current firm customers could be given the auction revenues from the sale of Congestion Revenue Rights. Thus, the existing customers would receive the market value of those rights. Under this approach, all of the Congestion Revenue Rights available on the system would be sold through an auction. At a minimum, the Congestion Revenue Rights sold in the initial auction would have to include point-to-point obligations. If there is interest from market participants and it is technically feasible, the auction could also include point-to-point options and flowgate rights.

380. The terms of the Congestion Revenue Rights would vary. Initially, a set percentage would be auctioned on a monthly basis, another set percentage would be auctioned for six months and another for one year. This rulemaking proposes that the regions be given flexibility in setting the initial terms for the Congestion Revenue Rights sold in auctions. Since congestion patterns can change significantly after the implementation of LMP, there may be a benefit to delaying the auction of multi-year

¹⁸⁶(...continued)

that the Congestion Revenue Rights stay with the load. So if a new retail marketer starts serving load previously served by the local utility, the retail marketer would get a proportionate share of the Congestion Revenue Rights.

Congestion Revenue Rights until after a start-up period. On the other hand, customers may desire long-term Congestion Revenue Rights to correspond to the term of the long-term contracts used to satisfy the long-term resource adequacy requirement. We seek comment on whether we should require long-term Congestion Revenue Rights in such cases. The Congestion Revenue Rights that would be sold during the initial auction would be the set of Congestion Revenue Rights that maximizes the value of the awarded Congestion Revenue Rights based on buyers' bids that is simultaneously feasible. The revenues from the auction would be given to the customers that are paying for the embedded costs of the system through an access charge.

381. In the long-term, the auction methodology has a number of advantages over the allocation methodology in a competitive wholesale market. First, the auction methodology makes it easier for load-serving entities to change receipt points (and thus supply sources) and obtain protection against congestion costs because of the more frequent auctions for Congestion Revenue Rights. The same would also apply to sellers seeking to sell to different buyers. In contrast, if Congestion Revenue Rights are directly assigned, holders of the Congestion Revenue Rights on congested paths may be reluctant to offer these in the secondary market. This could limit the ability of new suppliers to enter the market. This could be problematic particularly with Congestion Revenue Rights held by vertically-integrated utilities. Second, experience to date has been that there is a

more vibrant secondary market where Congestion Revenue Rights are auctioned rather than directly assigned.¹⁸⁷

382. This proposed rule establishes a preference for the auction of Congestion Revenue Rights. After a transition period, all Independent Transmission Providers would be required to auction their Congestion Revenue Rights. However, for an initial transition period of four years, this rulemaking proposes to allow regional flexibility on this issue. During a transition period, the Independent Transmission Provider after consultation with the Regional State Advisory Committee and stakeholders in a region, could decide to directly assign Congestion Revenue Rights. At the end of the transition period, the Independent Transmission Provider would be required to submit a filing to move to an auction for Congestion Revenue Rights with the auction revenues allocated to those that pay the access charge, or justify why a longer transition period is necessary. The customer that previously had been allocated the Congestion Revenue Rights would now receive the auction revenues. The customer could participate in the auction if it wished to retain the Congestion Revenue Rights. We seek comment on whether to allow a transition period before the start of Congestion Revenue Rights auction allocations and, if so, what the length of such a transition should be.

¹⁸⁷New York ISO auctions Congestion Revenue Rights and PJM directly assigns Congestion Revenue Rights. MISO has also proposed to initially directly assign Congestion Revenue Rights but to transition to an auction of Congestion Revenue Rights with an allocation of auction revenues to the customers that pay the embedded costs of the system.

3. Reciprocity Provision

383. In Order No. 888, the Commission included a reciprocity provision in the pro forma tariff. Under this provision, all customers (and their affiliates), including non-public utility entities, that own, control or operate interstate transmission facilities and that take service under a public utility's open access transmission tariff, must offer comparable (not unduly discriminatory) services in return.¹⁸⁸ The Commission also recognized that a public utility may deny service simply on a claim that the open access offered by a non-public utility was not satisfactory. Thus, the Commission developed a voluntary safe harbor procedure under which non-public utilities could submit to the Commission a transmission tariff and a request for declaratory order that the tariff meets the Commission's comparability (non-discrimination) standards. If the Commission found it to be an acceptable reciprocity tariff, the Commission would require the public utility to provide open access service to that particular non-public utility.¹⁸⁹

384. We propose to continue this approach to reciprocity. Further, we propose to grandfather all reciprocity tariffs that the Commission previously found met the comparability standards of Order No. 888. We request comment on this proposal.

4. Force Majeure and Indemnification Provisions

¹⁸⁸See Order No. 888 at 31,760; Order No. 888-A at 30,285.

¹⁸⁹Id. at 31,761.

385. In Order No. 888, the Commission recognized that the risk allocations regarding liability and indemnification "must be carefully drafted so that transmission providers and customers can accurately assess and account for their respective risks."¹⁹⁰ The Order No. 888 pro forma tariff contains a force majeure provision and an indemnification provision.¹⁹¹ The force majeure provision provides that neither the transmission provider nor the transmission customer will be liable to the other when they behave properly, but unpredictable and uncontrollable force majeure events prevent compliance with the tariff.

386. Under the indemnification provision, the transmission customer indemnifies the transmission provider against third-party claims that arise from the performance of obligations under the tariff. The Commission explained that the purpose of the indemnification provision was to allocate the risks of a transaction, and costs of the risks, to the party on whose behalf the transaction was conducted.¹⁹² Further, as the tariff did not obligate the customer to perform services on behalf of the transmission provider there was no comparable basis for imposing an indemnification obligation on the transmission provider. The Commission found it inappropriate to require the customer to indemnify the transmission provider from damages arising from the transmission provider's own negligence. Thus, a transmission customer is not required to indemnify the transmission provider in the case of negligence or intentional wrongdoing by the transmission

¹⁹⁰ Order No. 888 at 31,765.

¹⁹¹ See Sections 10.1 and 10.2 of the pro forma tariff.

¹⁹² See Order No. 888-A at 30,301.

provider.¹⁹³ The Commission further explained that while it was appropriate to protect the transmission provider when it provides service without negligence, the determination of liability in other instances should be left to other proceedings.

387. Since Order No. 888, several entities have sought to revise their open access transmission tariffs to include liability provisions arguing, among other things, that no current federal forum exists for entities that are now subject to Commission jurisdiction only and can no longer seek relief at the state level.

388. We recognize that there may be a need to include liability provisions in the Commission's pro forma tariff in circumstances in which there are no liability provisions available in a state tariff; however at this time, we are not prepared to propose a specific provision.¹⁹⁴

389. We seek comment on the following issues: Is there a need to include liability provisions in the Commission's pro forma tariff? Under what circumstances should liability protection be provided in a Commission open access transmission tariff (e.g., should we provide such protection only where it is not available through state tariffs)? If we adopt liability provisions, should they be generic or do they need to be adopted on a regional basis? Should the standards adopted in a Commission pro forma tariff reflect what was previously provided under state law? How do we resolve the issue in the multi-

¹⁹³ See Order No. 888-A at 30,299-300; Order No. 888-B at 62,080.

¹⁹⁴ We have included the indemnification and liability provisions from the existing pro forma tariff in the SMD Tariff pending review of the comments in this proceeding.

state context of an ISO or RTO? The Commission will review the comments filed and then hold a staff technical conference in the fall to further discuss this issue.

I. Market Power Mitigation and Monitoring In Markets Operated By The Independent Transmission Provider

1. Principles and Objectives

390. In a structurally competitive market, one with many buyers and sellers who cannot influence price, the market can assure an overall efficient outcome where prices indicate the value of additional supplies and conservation. The development of structurally competitive markets is the Commission's long-term goal. However, at this stage of the industry's evolution, wholesale electric markets are not yet structurally competitive in all respects. The two significant structural flaws are the lack of price-responsive demand and generation concentration in transmission-constrained load pockets. Given these structural defects, the Commission cannot rely on the interaction of supply and demand in all instances to ensure that prices are competitive and thus just and reasonable.

391. Cost-of-service regulation is not effective for spot market pricing of commodities such as electricity. In the past, customers were served by a monopoly supplier under cost-of-service rates, in which the fixed and variable costs of a company's generation portfolio were allocated over the expected hours of service to determine a cost per kWh. But today, the power needs of load-serving entities are met through a mix of sources, including the companies' generation portfolios, and long-term and spot market purchases from a variety of sellers, including independent producers and marketers. These do not

match the long-term arrangements needed for cost-of-service regulation. In this competitive context, cost-of-service regulation designed for long-term cost recovery is not well suited for determining appropriate spot market prices. When applied to spot markets, cost-of-service regulation blunts price signals and leads to inefficient investment and consumption decisions which over the long run increase costs for all customers.

392. When markets do not produce competitive outcomes, the Commission must use new regulatory tools to produce just and reasonable results. We propose new market power mitigation measures to deal with the consequences of major structural defects in wholesale electric markets, by approximating the outcomes that a competitive market would produce. These measures should function in markets that are not workably competitive, but not inhibit market operation in more competitive markets. Effective market monitoring and market power mitigation are critical elements of the Commission's plan to create and sustain competitive regional bulk power markets. Therefore, the Commission proposes rules for the spot markets to be operated by the Independent Transmission Provider to mitigate market power.

393. Market power is the ability to raise price above the competitive level.¹⁹⁵ This can be accomplished if the generator can withhold physical power (physical withholding) or cause physical power to be withheld through inflated bids (economic withholding).¹⁹⁶ Competitive prices over the long run should recover both the fixed and variable costs of efficient generating units. The challenge for market power mitigation on the supply side is to assure that it allows long-term competitive prices, which allows the opportunity to recover the fixed costs of the investment as well as the short-term variable costs of

¹⁹⁵The Commission's natural gas pipeline cases have used a definition of market power that examines the company's ability to raise prices significantly above a competitive level for a sustained period. *Alternatives to Traditional Cost-of-Service Ratemaking for Natural Gas Pipelines*, 74 FERC ¶ 61,076 at p. 61,230 (1996); and cases cited *id.* at n. 52. *See also*, *Alternatives to Traditional Cost-of-Service Ratemaking for Natural Gas Pipelines*, 70 FERC ¶ 61,139 at p. 61,403 (1995) (concerning transportation and storage services). These factors recognize that it is difficult to identify market power with precision, both because it is difficult to precisely identify the competitive price (which should recover both fixed and variable costs over the long run) and because it can be difficult to isolate the impact of one entity on the competitive price. These factors also recognize that there is an implicit cost/benefit assessment to decisions to intervene in the exercise of market power. The cost of intervention in transient price increases could be greater than the public benefit gained by the intervention. Commission decisions about when to intervene in an exercise of market power are important, but need to be tailored to the circumstances of the product and the industry. In the electric industry, electricity prices can spike for one hour or a few hours in ways that are less likely for natural gas pipeline transportation and storage rates, and the consequences can be quite different. Since the definition of market power and the decision when to intervene in its exercise are analytically distinct issues, in this rulemaking the Commission incorporates the concept of when to intervene in an exercise of market power into the choice of triggers for the market power mitigation mechanisms, rather than in the definition of what constitutes market power.

¹⁹⁶Market power can also be exercised by creating barriers to entry so other suppliers cannot reach the market or by causing other supplier's production costs to increase.

producing electricity. If some degree of scarcity pricing is not allowed, and generation only recovers short-term marginal costs, then some generators needed for reliability could fail to recover their full costs and may be retired. Worse yet, prices could be held so low that investors decline to invest in needed generation, transmission and demand-side projects because they do not see a reasonable expectation of recovering their costs.

394. The market power mitigation measures proposed here are designed to address the major structural defects in wholesale electric markets. The major structural defect on the demand side is the lack of price-responsive demand; when customers cannot respond to high prices by lowering their consumption, they cannot discipline price increases from suppliers. Absent demand response, market prices will reflect suppliers' bids alone, so we cannot rely on market prices to ration scarce supplies in all situations. Therefore, the market power mitigation needs to compensate for the lack of price-responsive demand in the market.

395. On the supply-side, structural problems tend to be more location-specific and time-dependent. For example, binding and sometimes unpredictable transmission constraints may restrict competitive alternatives and create opportunities for some sellers to increase prices above a competitive level, at least for any seller that knows some of its output will be required to meet load reliably. This problem is often described as a load pocket problem. In some load pockets, a specific generator may be identified as needed for

reliability, which gives it a local monopoly.¹⁹⁷ In other situations without severe constraints, the geographic market may be broader but if little generation divestiture or entry by non-affiliated generators has occurred, concentration of ownership may remain high. Market power mitigation needs to mitigate local market power, whether it arises because of a load pocket, transmission constraints, or ownership concentration.

396. To be effective, market power mitigation measures must be applied before the fact, since remedies after the withholding has occurred are disruptive to the market and increase regulatory risk to its participants, which increases costs to customers.

397. In sum, the challenge in developing an effective market power mitigation plan is to design a plan that allows markets to function where they are competitive and, where they are not, uses market mechanisms to facilitate the transition to competitive markets.

Market mechanisms can be used to approximate the outcomes that a competitive market would produce to provide the price signals for efficient investment and demand response. Because of the characteristics of electricity (it can be stored only in limited instances – pumped storage, compressed air, batteries) and the electric grid (flows follow the path of least resistance), even in regions where markets are generally competitive, transmission constraints may create non-competitive conditions during certain hours. In addition, when market power exists, the market power mitigation plan should be calibrated so that

¹⁹⁷This is also true for certain types of ancillary services (e.g., reactive power) where specific generators may have the ability to exercise market power because of their location.

it does not inefficiently suppress prices, or mask scarcity prices, providing the wrong economic signals for efficient investment or demand response.

2. Overview of the Market Power Mitigation Measures

398. The Commission proposes a market power mitigation plan composed of three mandatory components that are specifically tailored to the structural flaws in the wholesale electric markets and a voluntary fourth measure that could apply in unusual market conditions to assure that the high prices are not the result of market power.

399. The first measure addresses the local market power problem and is similar in concept to the reliability must run agreements that exist in the ISOs today. The market monitor will identify certain conditions in which certain generators are in concentrated geographic markets created by transmission congestion or reliability needs of the grid. These would include units needed to run to support the reliable operation of the grid or a set of units owned by a small number of companies. At those times, those units will have localized market power so that when they are required to provide their energy or ancillary services to the grid their bids into the market should be capped.¹⁹⁸ The conditions when their power must be supplied to the grid (a must-offer obligation) and the bid cap to apply would be specified in their participating generator agreement with the Independent Transmission Provider.

¹⁹⁸This would include a broader group of units than what are often referred to as reliability must run units.

400. The second component, a safety-net bid cap such as the \$1000 per megawatt-hour cap currently used in Northeast markets and Texas, addresses the lack of price-responsive demand. Sellers could freely offer any amount of energy to the spot markets constrained only by the safety-net bid cap. The safety-net bid cap should allow markets to produce prices that reflect some (and perhaps a significant) amount of scarcity when shortages of reserves or power exist. But absent demand response, it sets an outer bound on suppliers' ability to exercise economic withholding.

401. The third component of the market power mitigation plan is the resource adequacy requirement discussed in Section J. The resource adequacy requirement does not directly prevent withholding, but by expanding the resource alternatives it diminishes the incentive and the ability of suppliers to practice and profit from either physical or economic withholding.

402. While it is clear that the first three measures must be part of the Standard Market Design market power mitigation plan, there may be market conditions in which a fourth measure is needed. The fourth mitigation measure would deal with situations when non-competitive conditions may exist, by examining and possibly limiting bids from individual suppliers into the day-ahead and real-time spot markets if those bids are high due to withholding rather than scarcity. Exercise of this mitigation could be triggered by predetermined conditions or triggers (such as a sustained period of prices significantly above competitive levels), or by significant infrastructure problems in the market (e.g., sustained tight reserve conditions, as might be due to drought). This mechanism is like

the Automatic Mitigation Procedure (AMP) used by the New York ISO, and adopted recently for the California ISO. This mechanism would not be required for every region but may be adopted if the market monitor's analysis determines this measure is needed.

403. The implementation of the market power mitigation plan summarized above and described in more detail below will rely on the results of an initial competitive market analysis by the Independent Transmission Provider's market monitor in each region. This will identify at the outset the persistent load pockets or other conditions that create local market power. This analysis will be filed with the Commission as part of the implementation process for Standard Market Design and subject to comment from all interested parties. After Commission review, it will form the basis for the mitigation measures that are applied by the Independent Transmission Provider. It then will be updated annually to review the continuing effectiveness of the market power mitigation.

404. The market power mitigation measures proposed rely principally on mitigating market power in spot markets. Mitigation would only apply to products traded in the spot markets operated by the Independent Transmission Provider, not to products traded under bilateral contracts outside the Independent Transmission Provider's spot markets. This is the least intrusive framework for market power mitigation but at the same time provides very effective protection against market power.

405. Although power and operating reserves purchased in the organized spot market are only a small percentage of total purchases, mitigating the organized spot market is an

effective way of mitigating market power generally.¹⁹⁹ Bilateral contracts generally reflect buyer and seller expectations of prices in spot markets. Therefore, market power mitigation in the organized spot market will effectively discipline market power in bilateral markets as well.²⁰⁰ However, if spot market prices are over-mitigated, it may weaken incentives for buyers to contract in bilateral markets and expose spot market prices to greater price volatility. Regular reassessment of the market power mitigation practices can prevent this outcome, and, as discussed infra, the market monitor will be required to annually reassess the effectiveness of the market power mitigation.

3. Market Power Mitigation For Local Market Power

406. Local market power principally arises either from the concentration of generator ownership within a load pocket, or the need for local units to operate to assure system reliability and stability within the load pocket. Local market power can arise from both persistent and foreseeable congestion, or from sporadic transmission congestion. Although local market power can arise from these different conditions, the mitigation method proposed here can be effective at mitigating the local market power regardless of how it arises.

¹⁹⁹Stoft, Steven. Power System Economics. New York, NY: Wiley-IEEE Press, 2002, Section 2-4.5, "How Real-Time Price-Setting Caps the Forward Markets," p. 150.

²⁰⁰Relying on mitigating market power in the spot market has been an effective mitigation method in the New York ISO under its AMP, and the California ISO since May, 2001.

407. In the existing ISOs in California and the Northeast, participating generator agreements are used to set out the operating terms, conditions and obligations concerning the dispatch of a generating unit, serving principally a reliability purpose. Under the Standard Market Design pro forma tariff all generators dispatched by the Independent Transmission Provider would enter into a participating generator agreement.²⁰¹ Standard Market Design will require these participating generator agreements to include provisions to mitigate local market power.

408. The participating generator agreements, which would be filed with the Commission, would identify the non-competitive conditions when the generator with local market power would be required to offer its energy either by scheduling a bilateral transaction or by offering all available energy to the spot markets. This would be a must-offer requirement. The requirement would apply when the generator's power is needed to maintain the reliable operation of the grid, and also when there are insufficient competitive alternatives. The participating generator agreement would specify the conditions that would give rise to a generator's must-offer requirement, and would also specify bid caps that would apply when the generator was required to bid into the day-ahead and real-time markets. In non-competitive conditions, the generator's bids could not exceed the capped values. Although the participating generator agreement may restrict a generator's energy and operating reserves bids, the generator would still receive

²⁰¹SMD Tariff Section A.9.2.

a market-clearing price and additional revenue to cover start-up and no-load costs.²⁰² The capped bid could also set the market clearing price.

409. In addition to the bid caps specified in the participating generator agreements, local market power also will be limited through bilateral contracts between load-serving entities and the generators. Under the resource adequacy requirement, load-serving entities must have enough resources to meet their demand to ensure the reliability of the grid. It can be expected that some of those resource requirements will need to be fulfilled with contracts with generators within their load pocket to ensure that the resource is deliverable during peak or congested periods. Bilateral contracts are an effective way for a buyer to mitigate the market power of a seller.²⁰³ The load-serving entities can be expected to include provisions in these contracts specifying when a generator must run to meet any reliability needs in that location and the price to be paid. Whenever a generator is scheduled to run under a bilateral contract, this will fulfill its must-offer obligation in the participating generator agreement with the Independent Transmission Provider.

410. Under the participating generator agreements, when conditions are not competitive, that is, when there are insufficient alternatives available to meet load in that location, a generator must run to provide all its available capacity to the grid, either by

²⁰²SMD Tariff section F.1.11. The generator's legitimate minimum run times would also be honored under the provisions of SMD Tariff section F.1.5.

²⁰³See Comment of the Staff of the Bureau of Economics and the Office of the General Counsel of the Federal Trade Commission, Docket No. RM01-12-000 (July 23, 2002).

scheduling a bilateral transaction or bidding into the spot market. The need for the generator to be producing could be identified either in the day-ahead market based on projected system conditions or in real time. In the day-ahead market, all available capacity would include all capacity not sold bilaterally and scheduled or on an outage. In the real-time market, all available capacity would include all non-producing capacity (not delivered to the market) i.e., capacity not on a planned or forced outage.²⁰⁴

411. The Commission invites comment on how to structure the local market power mitigation, particularly on how to define the noncompetitive conditions which should trigger the mitigation, and on how bid caps should be structured for generators operating under a participating generator agreement.

412. There are some options for dealing with the risk of a forced outage inside a load pocket. One is for a portion of available day-ahead capacity to be exempt from the bid-in requirement to reflect forced outage risk in real time. Another possibility is to allow generators to provide all available capacity in real time at a capped bid in lieu of bidding in the day-ahead market to accommodate generators that have significant risk or opportunity costs. A third option would vary depending on whether the generator receives a reserve capacity payment. If the generator receives a capacity payment, that payment compensates for the outage risk so the generator should be obligated to deliver

²⁰⁴Under the Standard Market Design tariff, all units scheduled day ahead under a must-offer obligation, but not needed in real time would get paid their start-up and no-load costs.

energy or to pay for substitute supply from some other source. If the generator does not receive a capacity payment, then it should not have to bear the risk for a legitimate outage. Units declaring a forced outage would be subject to audit by the market monitor. If the outage is found to be unjustified, then the generator should be subject to a penalty. The Commission requests comment on the penalty that would be appropriate to deter unjustified forced outages.

4. The Safety-Net Bid Cap

413. If bid-in capacity is generally insufficient to meet both operating reserve requirements and load, capacity rights associated with the resource adequacy requirement may be exercised by load-serving entities that have secured sufficient capacity so that they will not be interrupted. However, in this situation, lack of demand response can result in dramatic increases in market-clearing prices, even with comprehensive mitigation on the supply-side, if imports can bid in at unrestrained levels. In this case, imported power from adjacent markets could set a market-clearing price above the marginal cost of the highest cost unit dispatched within the market.²⁰⁵

Current markets in the Northeast and Texas rely on a \$1000 per megawatt-hour bid cap, regardless of market conditions, as a safety-net that may be binding in this situation.

The Commission proposes to adopt a safety-net bid cap as part of the market power

²⁰⁵Generators outside the region would not have participating generator agreements with the Independent Transmission Provider, with provisions for addressing local market power, and neither would marketers.

mitigation plan here. Under this proposal, no bid to supply can exceed this level, regardless of cost or risk or location, even if the market is confronted with a genuine operating reserve shortage. However, if the monitor establishes that some units may provide power at a cost that exceeds the safety-net, a higher price for those units would be justified. In California, for example, imports are not allowed to set the market clearing price. However, in the market power mitigation framework proposed here imports would be allowed to set the market clearing price in order to get a proxy for a scarcity price, up to a capped value. If requirements cannot be satisfied with bid-in imports that would be subject to the safety-net bid cap, then load that has not met its resource adequacy requirement should be penalized as described in the Resource Adequacy section. A safety-net bid cap, such as the \$1000 per megawatt-hour cap in the Northeast and Texas, can serve as a proxy scarcity price under Standard Market Design. The Commission requests comment whether the safety-net bid cap should be uniform across an interconnection, so that there would be one cap applicable in the East and another applicable in the West.

414. Comment is requested on how to determine an appropriate value for such a cap. It is important to examine the implicit trade-off between bilateral capacity payments, the safety-net bid cap and local market power mitigation. That is, a bid cap that constrains scarcity prices would be expected to translate into higher bilateral capacity payments under a contract to fulfill the long-term resource adequacy requirement. With a higher safety-net bid cap, perhaps one based on the value of lost load, smaller bilateral capacity

payments would be required to maintain the same level of resource adequacy in the absence of price.

5. Mitigation Triggered by Market Conditions

415. The Commission proposes a fourth voluntary market power mitigation measure which may be recommended by the market monitor during the Standard Market Design implementation process, or any time thereafter. This measure, if needed, would apply to unanticipated and sustained market conditions that would give the ability and the incentive to exercise market power. For example, extreme supply or demand conditions to which the market cannot quickly adapt, such as the loss of significant hydropower capacity because of drought, or force majeure events such as a major transmission line outage. These kinds of events, which are not transitory, can provide opportunities to exercise market power even in a market that is normally workably competitive. It may be appropriate for other conditions to trigger this mechanism. We seek comment on what these triggers should be. Although market-clearing prices would be expected to rise in these situations, and perhaps sharply and significantly, it may be important for the market to have the assurance that the price increases are attributable to the extreme circumstances and not to the exercise of market power. An AMP mechanism such as those approved by the Commission in New York ISO and California could provide this kind of assurance.²⁰⁶

²⁰⁶See California Independent System Operator Corp., 100 FERC ¶ 61,060 (2002). See New York Independent System Operator, Inc. *et al.*, 99 FERC ¶ 61,246 (2002). Although AMP was in effect in all of New York, it was only triggered on four occasions, (continued...)

416. This kind of mechanism may not be necessary in every region. If a market monitor proposes such a mechanism, the proposal must include the specific triggers that would be used to initiate this form of market power mitigation along with the details of the mitigation method. Since this form of market power mitigation is for temporary market conditions, it will be equally important for the market monitor to indicate the criteria to determine when the market has returned to normal competitive conditions and this market power mitigation method will be suspended.

417. The details of this market power mitigation method, including the triggers, would be set out in the Independent Transmission Provider's tariff. If market conditions developed that satisfied the pre-determined triggers for the mechanism, it would be the market monitor's responsibility to give notice to the public and the Commission that the tariff mechanism had been triggered. The mechanism would then automatically take effect until the conditions developed that satisfied the pre-determined triggers for the suspension of this market power mitigation mechanism. If a market monitor proposes to use this form of market power mitigation, the details of the mechanism and the triggers would be subject to comment by all interested parties, and review by the Commission.

6. Establishing Bid Caps or Competitive Reference Bids

418. The mitigation for local market power, through the participating generator agreements, relies on must-offer obligations to mitigate physical withholding and bid caps

²⁰⁶(...continued)
reflecting conditions in eastern New York.

to mitigate economic withholding. Mitigating economic withholding entails determining appropriate bid caps for all bid-in parameters.²⁰⁷ The unit-specific bid caps in the participating generator agreements serve as proxy competitive bids for energy, regulation service, and operating reserves, and for other unit-specific operating parameters such as minimum run times and high and low operating levels. Bid caps should reflect the marginal cost – including opportunity cost – of offering all capacity, including power that may be supplied only under limited conditions. Other bid-in parameters should reasonably reflect operating conditions consistent with good engineering practice under competition.

419. The development of bid caps, especially for generators with significant opportunity costs such as hydropower and energy-limited units, is difficult and can be controversial. Nevertheless, this mitigation plan would require that each generator, including hydropower and energy-limited units, that may have local market power would need to have an agreement establishing bid caps for all bid-in parameters if its power is needed for the grid or local market power mitigation is necessary.

420. The Commission has approved several options for setting default energy bids that in some circumstances serve as energy bid caps. They include: (1) default bids based on various averages of previously selected in-merit bids; (2) default bids based on various cost measures, usually a measure of operating cost adjusted for fuel costs; and (3) default

²⁰⁷These same considerations would apply if the Commission adopted an AMP-like mechanism with bid caps or competitive reference bids.

bids agreed through contract or negotiation. For many fossil-fired units, an estimate of operating costs plus a margin, such as ten percent, could provide a reasonable bid cap for a unit's energy bid when competitive forces cannot be relied on, similar to PJM's approach for mitigating reliability must run units.²⁰⁸ Although fossil-fired units may have opportunity costs not fully reflected by operating costs, an adder, such as that used by PJM, is one way to allow flexibility to respond to these uncertain costs. The Commission requests comment on whether the level of the adder should be reviewed on a region-by-region basis or if the Commission should establish a uniform adder, and if so, at what level.

421. For peaking units that are likely to set market clearing prices when they are dispatched, the must-offer requirement coupled with mitigation that sets bid caps at marginal cost could result in revenues that fail to recover fixed costs over a reasonable period of time. Although such units may recover additional revenue in capacity and reserves markets, bid caps for these units could also reflect a "scarcity" premium or adder to compensate for the lack of price-responsive demand that would otherwise set the price when these units were dispatched. The average cost of a new peaking unit at a given location operated over a given number of hours could form the basis for setting such a premium. This kind of adjustment to bid caps for peaking units could help support

²⁰⁸This method may not work for fossil-fired units that are only permitted to run a limited number of hours due to environmental restrictions. These energy-limited resources are discussed below.

reliability until demand-side measures for responding to price were more fully incorporated in markets. The Commission requests comments on whether this approach or other adjustments to bid caps for peaking units might usefully substitute for demand response in the near term.

422. For hydropower and other energy-limited resources much of the difficulty in determining an appropriate energy bid cap for these units comes from the difficulty of assigning a value to their temporal opportunity costs. However, the times when it would be necessary for the transmission provider to call on power from these sources are likely to be times when prices are high and these units would want to be scheduled in any event. At all other times, hydropower units, in particular, should be offering all available capacity as operating reserves since their marginal operating costs are close to zero, but they may have high temporal opportunity costs. In other words, there appears to be no economic reason why such units should not always be fully committed either to the bilateral market or spot markets for operating reserves. Consequently, it appears unnecessary to cap energy bids from such resources below the safety-net bid cap as long as their bids to provide operating reserves were always in-merit. Alternatively, other energy-limited resources might be allowed to submit a bid that states a total megawatt-hour availability over the day and allow the market operator to schedule the power from the unit in the hours when the price is highest. Comment is requested on these and other approaches to establishing reasonable caps for energy bids.

423. Another alternative for hydropower, and other energy-limited resources, would be for the unit operator to submit a seasonal or monthly schedule for when the unit would not be expected to operate. This would enable, for example, hydropower units to specify the periods when they would expect to need to preserve water or flow water to satisfy environmental conditions. While these units have many legitimate competing needs for the water flow, it is still possible for a hydropower generator to engage in physical or economic withholding. In the existing ISOs, generators must submit a schedule for planned outages, which is coordinated by the ISO to ensure that outages occur when they are the least disruptive to the markets. The Independent Transmission Provider is expected to continue to perform this outage coordination function under Standard Market Design. Scheduling outages in advance, coupled with auditing by the market monitor, would provide a way to evaluate whether failures to run were from withholding or legitimate limitations. For hydropower units, for which the marginal costs are primarily opportunity costs, this method may be a sufficient check against withholding so that it might be unnecessary to have a bid cap for these units. The Commission requests comment on these alternatives.

424. Any parameters that a generator may include in its bid may require a cap or other restraint. For example, PJM caps regulation service at \$100 per megawatt-hour, and New England uses energy prices to cap prices for spinning reserves. Standard Market Design would also allow availability bids for these products. The participating generator agreements should also contain bid caps for these operating reserves when they are

needed for the operation of the transmission system and non-competitive conditions exist. However, the Commission requests comment on how to identify the options for determining competitive bid caps for regulation service and operating reserves, including availability bids, that should be established for day-ahead and real-time markets.

425. In the New York and PJM day-ahead markets, the unit-specific energy bid cap applies to the day-ahead market where separate bids for start-up and no-load costs are also available and would also be available under Standard Market Design. Market power mitigation should also establish caps for these bids and a variety of bid-in operating parameters, such as low and high operating levels and minimum run times, if non-competitive circumstances would permit sellers to manipulate these parameters to get unjustified higher up-lift payments. PJM, for example, does not mitigate the start-up and no-load bids or certain operating parameters, but it only allows units to change these values once every six months. New York permits greater flexibility and uses various screens to assess whether a seller is behaving non-competitively and should be mitigated.

426. Several approaches could be used for establishing bid caps for these particular parameters. One possibility would be to rely on engineering data, such as from the manufacturer about the specific type of unit, to establish caps for start-up and no-load bids and certain operating parameters, and give generators the flexibility to bid within those ranges without mitigation. These ranges would also be included in the generators' participating generator agreements. Just as with energy bids, a bid above the range could be mitigated if the bid raised market-clearing prices or uplift payments above a

competitive benchmark level by a significant amount. Because factors that might cause generators to modify start-up and no-load bids and parameters such as minimum run times generally are thought to be less variable than factors that may influence energy bids, caps for these variables may be quite tight.²⁰⁹ In fact, PJM's approach to permit changes to these parameters once every six months may be a simpler alternative that does not unduly restrict competitive generator behavior. Comment is requested on this approach and on other ways to prevent sellers from manipulating these bids and operating parameters to increase market-clearing prices and uplift payments.

427. In the implementation filing, the market monitor would propose tariff language that sets forth the process for setting the bid caps for individual units or any formulas that might be used for this purpose. The market monitor would be responsible for collecting and verifying data from these units to establish appropriate caps for energy bid values consistent with the procedures in the Independent Transmission Provider's tariff. This could be controversial, especially for generators in load pockets that may effectively face "mitigation" in most situations. The Commission requests comment whether the Commission should establish a formula for determining the bid caps or whether the Commission should review the proposals developed in each region.

7. Exemptions

²⁰⁹For example, energy prices could change frequently because of differences in the cost of fuels such as natural gas.

428. It is appropriate to exempt certain sellers from the market power mitigation.

Specifically, sellers who control a small amount of capacity in the market, for example no more than fifty megawatts, would be exempt from mitigation. Sellers with little capacity would have little incentive to exercise market power since a non-competitive bid could eliminate their only unit from the dispatch. However, the Commission requests comment whether any other sellers should be exempt from the mitigation because they have insufficient incentives to withhold.

8. Monitoring

429. Market monitoring should be conducted on an on-going basis by a market monitoring unit that is autonomous of the Independent Transmission Provider's management and market participants. The market monitoring unit may be located within the offices of the Independent Transmission Provider, to permit easy access to the market data and operations personnel, or it may be physically located elsewhere.

430. The market monitor will be expected to report directly to the Commission, and the independent governing board of the Independent Transmission Provider. This will include reporting at regular intervals on the general performance of the markets in its region and reporting, on a timely basis, observed attempts at market manipulation or factors that impair the efficiency of the market. Although the market monitor will be accountable only to the Commission and the governing board, it should share its analyses and reports with the management of the Independent Transmission Provider and the

Regional State Advisory Committee. This will enable the committee to carry out its advisory functions in an informed manner.

431. The market monitor must focus both on the functioning of the markets run by the Independent Transmission Provider as well as the conduct of individual market participants. The market monitor should focus on identifying factors that might contribute to economic inefficiency. Such factors include market design flaws, inefficient market rules, entry barriers to new generation, including distributed generation, barriers to demand-side resources, transmission constraints and market power. In monitoring for exercises of market power, the market monitor should focus principally on detecting economic and physical withholding (as distinct from the normal operation of supply, demand, and true scarcity). For entities that own both transmission and generation assets, withholding behavior could include both generator and transmission outages. For example, instead of directly withholding a generator's power, a market participant with transmission assets could effect the same end by derating a transmission line needed to deliver the generator's power to the market. Monitoring should be designed to detect this kind of behavior.

432. The Commission requests comment on whether the market monitor should also be responsible for monitoring the Independent Transmission Provider's operations, in addition to the markets and the market participants. Specifically, should the market monitor evaluate whether the Independent Transmission Provider treats market participants neutrally, without undue discrimination?

433. To meet its responsibilities, the market monitor must have the ability to collect and evaluate necessary data provided by the Independent Transmission Provider and market participants. The market monitor would have the responsibility to propose to the Commission, and the Independent Transmission Provider's board changes to market rules, if they provide inefficient incentives to market participants, and to promptly identify circumstances that may require additional market power mitigation so that remedies can be put in place prospectively.²¹⁰ The market monitor would also be required to provide a comprehensive analysis and report of market structure and individual generator conduct in the spot markets, at least annually, to evaluate the overall efficiency of spot market operations, the market for Congestion Revenue Rights, and how the balance between resources and demand in the region affects the market's ability to efficiently serve load at least cost. In addition, the market monitor must also annually assess the effectiveness of any mitigation actions taken and review the terms, conditions, and bid caps in the participating generator agreements. Finally, the market monitor must engage in surveillance to insure that market participants comply with the rules in the Independent Transmission Provider's tariff.

434. The work and findings of the market monitor must be integrated into the regional planning process. The market monitor's analysis of the markets will identify load pockets and can help provide direction for needed investment in generation, including distributed

²¹⁰The changes would only go into effect after Commission approval.

generation, demand response capability, and transmission infrastructure to improve the competitive structure of the markets.

435. The Commission proposes here the basic elements of a market monitoring plan to be used by each market monitor. The Commission staff will convene a conference in the Fall to discuss and further develop the essential elements that should be required in a standard market monitoring plan. After getting additional public input at the conference, Staff may propose additional detail for the market monitoring plan, which the Commission may adopt, after an opportunity for public comment.

a. Framework for analyzing market structure and market conduct

436. The Commission intends to require the use of a core set of questions and analytical techniques to be used by each market monitor to assess market structure, participant behavior, market design, and market power mitigation. This will facilitate inter-regional comparisons. Examining this core set of issues using techniques reflecting "best practices" would be an essential part of the monitor's responsibilities that allows inter-regional comparisons. However, specifying these core requirements here should not prohibit or discourage monitors from expanding their analyses where regional differences or unanticipated events warrant it. In fact, because markets and monitoring are in a formative stage, the Commission would need to continue to facilitate communication between market monitors to share insights and develop common approaches.

437. An important focus of market monitoring will be structural market conditions since the Commission's ultimate goal is to foster structurally competitive regional bulk power markets. Academic analysts and market monitors have examined the competitiveness of current spot markets using various approaches and data. Some have focused on developing a simulated competitive benchmark that can serve as a reasonable measure of the market's overall efficiency.²¹¹ Others have examined whether specific generator bidding behavior has been consistent with profit maximization under competitive conditions.²¹²

438. Some monitors have estimated whether average generator profitability would cover costs of a gas-fired peaking unit and provide sufficient inducement for entry.²¹³ Most monitors also track bidding patterns so that sudden, inexplicable changes can be investigated promptly to evaluate whether market power is a cause of the change.²¹⁴ Monitors also track changes in concentration, unplanned generator and transmission

²¹¹See, e.g., Borenstein, S., J.B. Bushnell, and F. Wolak (1999). "Diagnosing Market Power in California's Deregulated Wholesale Electricity Market." POWER Working Paper PWP-064, University of California Energy Institute, available in <<http://www.ucei.berkeley.edu/ucei/pwrpubs/pwp064.html>>.

²¹²Joskow, P.J., and E.P. Kahn (2001). "A Quantitative Analysis of Pricing Behavior in California's Wholesale Electricity Market During Summer 2000." NBER Working Paper No. W8157. National Bureau of Economic Research.

²¹³See, e.g., PJM Interconnection State of the Market Report 2000.

²¹⁴See, e.g., New York Market Advisor Annual Report on The New York Electricity Market for Calendar Year 2000, by David B. Patton, Ph.D., Capital Economics, April, 2001.

outages, and changes in various operating parameters that may signify market power problems.²¹⁵ Although the reports have been very useful in enhancing our understanding of a wide range of issues, the approaches have been varied, key questions have been framed differently and, importantly, the markets have not had the same design. As a consequence, results have not been comparable across markets. With the widely varying market designs of the past, greater comparability across regions was not feasible. However, these analyses have served as a useful starting point for developing a standard analytical framework.

439. The Commission proposes to require each monitor to perform a structural analysis of the region that would include: (1) market concentration including by type of generation, (2) conditions for entry of new supply, (3) demand response, and (4) transmission constraints and load pockets that give sellers the ability and incentive to exercise market power. This analysis would be performed prior to the implementation of the Standard Market Design, in order to implement the market power mitigation. It also would be performed annually to reassess and adjust the market power mitigation, and to evaluate the conditions of the market.²¹⁶

²¹⁵See, e.g., Annual Market Report, May 2000-April 2001, ISO New England, August 1, 2000.

²¹⁶The monitor should particularly pay attention to concentration in the regulation and operating reserves markets, and consider the amount of supply relative to demand, and propose specific market power mitigation measures for these markets if necessary.

440. In addition, the Commission proposes to require an annual assessment of the performance of the markets operated by the Independent Transmission Provider. This assessment would use a competitive benchmark to assess market performance as an additional means of assessing the effectiveness of the market power mitigation.

441. Comment is requested on how the monitor should address these and other topics, to develop useful measures that permit inter-regional comparisons. For example, concentration measures stratified by generator type might better identify competitive alternatives under various demand conditions. Estimates of generator profitability, such as PJM and ISO-New England have used in the past, might be a useful measure of incentives for generator entry. These estimate the degree to which a hypothetical unit operating in all profitable hours would have recovered its costs. Although it is not a definitive profit estimate for any particular generator, it may be a useful measure for comparing incentives for generator entry across market or regions.

442. A core set of questions and analytical techniques must also be developed for monitors to use to evaluate conduct of market participants in the transmission and spot markets operated by the Independent Transmission Provider. Analysis of generation and transmission outages is central because these can be forms of withholding. Because some owners of generation also own transmission, monitors must review any planned transmission outages, for example, to make sure that scheduling outages could not be used to enhance or create opportunities to exercise generator market power. Analysis of generator conduct might also include a review of bidding behavior in the spot markets

operated by the Independent Transmission Provider to identify any auction design flaws that may give market participants an unanticipated incentive and ability to manipulate market-clearing prices or up-lift payments. The monitor should also evaluate the effectiveness of the participating generator agreements in mitigating market power where market structure is not sufficiently competitive.

443. Finally, the monitor must analyze the operation of the congestion management system and the market for the resale of Congestion Revenue Rights for evidence of market power or manipulation. The monitor must also assess whether those who collect congestion revenues are in a position to influence transmission expansion plans that can affect congestion revenues and report on the incentive structure of those arrangements.

444. Any flaws in the market rules that may be identified by the monitor and any market participant conduct that indicates the ability to exercise market power under the market rules in effect would be remedied prospectively after Commission authorization of changes to the market rules. However, if the conduct violates existing rules, the market monitor must have the necessary tools to investigate the conduct and to penalize it. These will be discussed in the sections below.

445. An important adjunct to the market power mitigation and monitoring plan will be a clear set of rules governing market participant conduct with the penalties for violations clearly spelled out. The Commission proposes to require the Independent Transmission Provider to include in its tariff certain minimum behavioral rules, which will be monitored by the market monitor. These will include, at a minimum, the following rules:

- (1) **Physical Withholding:** Entities may not physically withhold the output of an Electric Facility (Generating unit or Transmission Facility) by (a) falsely declaring that an Electric Facility has been forced out of service or otherwise become unavailable, or (b) failing to comply with the must-offer conditions of a participating generator agreement.
- (2) **Economic Withholding:** Entities may not economically withhold by submitting high bids that are not consistent with the caps specified in the tariff or the participating generator agreements.
- (3) **Availability Reporting:** Entities must comply with all reporting requirements governing the availability and maintenance of a Generating Unit or Transmission Facility, including proper Outage scheduling requirements. Entities must immediately notify the Independent Transmission Provider when capacity changes or resource limitations occur that affect the availability of the unit or facility or the ability to comply with dispatch instructions.
- (4) **Factual Accuracy:** All applications, schedules, reports, or other communications to the Independent Transmission Provider or the Market Monitor must be submitted by a responsible company official who is knowledgeable of the facts submitted. All information submitted must be true to the best knowledge of the person submitting the information.
- (5) **Information Obligation:** Entities must comply with requests for information or data by the Market Monitor or the Independent Transmission Provider that are consistent with the tariff.
- (6) **Cooperation:** Entities must assist and cooperate in investigations or audits conducted by the Market Monitor.
- (7) **Physical Feasibility:** All bids or schedules that designate resources must be physically feasible within the limits of the resource, i.e., the resource is physically capable of supplying the energy, ancillary service, or demand response needed to fulfill a schedule or bid according to the physical limitations of the resource.

446. These rules must be accompanied by predetermined penalties, as discussed below in the Enforcement section.

b. Data Requirements and Data Collection

447. Data collection should be targeted to providing monitors with information necessary to answer the required questions covering critical issues regarding market structure, participant behavior, and market design. These data would be acquired from various public sources and in the normal course of operating the markets. They would include: (1) market statistics and indices, such as market-clearing prices and system-wide congestion costs; (2) data on system conditions, such as transfer capability and planned and forced outages; (3) information on other prices, such as fuel prices and prices in adjacent markets; (4) information on load served from the spot market; (5) data relating to generator bidding patterns; and (6) information on Congestion Revenue Rights.

448. In addition, monitors must have the ability to obtain data on generator production and opportunity costs and information on the operating status of transmission and generation facilities that relate to claimed outages or deratings. Generator-specific data on all relevant costs and operating parameters – e.g., start-up, no-load, environmental, fuel, maintenance, ramp rates, low and high operating levels, and heat rates – may also be relevant to establishing appropriate bid caps for participating generator agreements.

These data when combined with information acquired in the normal course of business operations and schedules for planned outages should give monitors the information they need to fully analyze the competitiveness of the markets operated by the Independent Transmission Provider.

449. As a condition for participating in the spot markets, and using the transmission grid, market participants must agree to provide the market monitor with any information requested. Since the ability of the market monitor to perform his or her monitoring role is dependent upon the ability to acquire the necessary information, the monitor must have the ability to require market participants to provide information. This is an important enforcement tool. The Independent Transmission Provider's tariff should specify the penalties that would apply to market participants who fail to comply with an information request from the market monitor. Market participant objections to market monitor information requests will be resolved by the Commission on an expedited basis because delays in providing information could result in continuing harm to the market. In any such dispute the Commission will give substantial deference to the market monitor's stated need for the information.

450. All information obtained by the monitor that is specific to a market participant would be treated confidentially. Any disputes concerning how the confidential information could be used would be resolved by the Commission, before the data are released to the public. Since the Commission has oversight responsibility for wholesale electric markets, any data collected by the market monitor would be available to the Commission and the confidentiality of the data would be protected by the Commission under its regulations.

c. Reporting Requirements

451. At a minimum, the monitor would be required to submit an annual report to the Commission and the Independent Transmission Provider's governing board, and share that report with the Regional State Advisory Committee. The report would include: (1) a general description of the market operations, supply and demand, and market prices; (2) an analysis of market structure and participant behavior following guidelines described above; (3) an evaluation of the effectiveness of mitigation measures taken; (4) an overall assessment of market efficiency perhaps using a simulated competitive benchmark as some have developed; (5) an evaluation of barriers to entry for generating, demand-side, and transmission resources; and (6) any recommended changes to market design or market power mitigation measures to improve market performance. The report would also include a discussion and analysis of any region-specific issues that the monitor judges important to achieving a competitive outcome. This could also be particularly useful to the planning process in determining where expanded transmission capacity might reduce market power problems in load pockets. The annual report would be made public, with appropriate protections to maintain confidentiality, if necessary.

452. In addition, the market monitor will be required to report to the Commission, through the Office of Market Oversight and Investigation, any instances of conduct by market participants that appear to be inconsistent with the Independent Transmission Provider's tariff. Early reporting of questionable conduct will permit coordination between the market monitor and the Commission's investigative staff to determine the

best methods for developing the facts and addressing conduct that could be harmful to the market.

453. The Commission requests comment whether additional reporting requirements are needed.

d. Enforcement of the Tariff Rules

454. The market monitor must play an important role in the enforcement of the market rules contained in the Independent Transmission Provider's tariff. In this role the market monitor will need to coordinate closely with the Commission's investigative and enforcement staff. However, to ensure effective enforcement, the market monitor must have adequate authority to investigate market participant conduct and the Independent Transmission Provider must have a set of predetermined penalties to apply to conduct that is in violation of the rules of the Independent Transmission Provider's tariff.

455. As a condition of participating in the markets operated by the Independent Transmission Provider and using the transmission grid operated by the Independent Transmission Provider, the Commission proposes to require market participants and transmission customers to agree to predetermined penalties that would apply to violations of the tariff rules. Since the tariff rules are intended to ensure the fair and efficient operation of the markets, the penalties should be designed to deter conduct that is inconsistent with the fair and efficient operation of the markets. Specifically, the penalties should deter conduct that results in an economic benefit derived from a violation of the rules. The penalties should, at a minimum, require payment of the economic

benefit derived by the violator from violating the rules. Where the violation could result in conduct that could be harmful to the reliability of the grid, it would be appropriate for the penalty to be significantly higher to serve as a deterrent for the conduct. The Independent Transmission Provider's tariff must specify the conditions that would apply for each level of penalty.

456. It may be appropriate to build into the tariff standards for mitigating the penalty. Some standards that could be used are: the impact on the operation of the grid, the financial impact on the violator, and any good faith efforts to maintain compliance. The Commission requests comment on the conditions that would justify mitigation of the penalty.

J. Long-Term Resource Adequacy

457. To operate the transmission system reliably, the transmission operator must be able to balance generation and load at all times. This requires adequate electric generating, transmission, and demand response infrastructure. Some lead time is needed to develop adequate infrastructure for the future through self supply or bilateral contracting.

458. Resource adequacy today must be assessed at the regional level. Because all customers in an interconnected region are interdependent, a shortage of resources for some customers in the region can lead to a shortage for the entire region, which threatens reliable grid operations and risks sustained shortages with attendant high prices for the region.

459. We propose a resource adequacy requirement to provide for sufficient supply and demand resources to avert such shortages. Under these procedures, we believe that involuntary curtailment will rarely if ever be employed. However, consistent with current policies, the proposal must include procedures for such emergency conditions.

1. The Reason for the Requirement

460. The Commission proposes to adopt a resource adequacy requirement to help ensure development of the infrastructure needed for reliable transmission system operation. Because electricity cannot be generated and easily stored for future delivery, extra generating and demand response resources are needed to serve a function similar to storage in the natural gas industry; other commodity markets would call these a supply inventory. The cost of necessary reserves is analogous to the necessary cost of storage or inventory.

461. A requirement to assure adequate long-term resources is currently needed because spot market prices do not consistently signal the need for new infrastructure in the electric power industry. Most resources take years to develop and spot market prices alone may not signal the need to begin development of new resources in time to avert a shortage. Moreover, spot market prices that are subject to mitigation measures may not produce an adequate level of infrastructure investment even after a shortage occurs. Further, as long as regional resources are made available to all regional load-serving entities and their customers during a shortage, such entities have the incentive to lower their supply costs

by depending on the resource development investments of others, a strategy that leads to systematic under-investment in infrastructure by all load-serving entities in the region.²¹⁷

a. Spot Market Prices Alone Will Not Signal the Need to Begin Development of New Resources in Time to Avert a Shortage.

462. The spot market price does not yet work well to produce long-term reliability investment, even without price mitigation, for several reasons. Extra resources need to be planned in advance for electricity because, when prices rise, demand is not reduced quickly and new generation cannot be added quickly. Both the demand for electricity and the supply of new generating capacity generally respond very slowly to price.

463. Regarding demand response, most retail customers buy power at a regulated fixed price. Even in states that have approved retail competition, customers are often shielded for years from price changes by a rate freeze. They are unaware of hourly changes in the cost of producing electricity. Electric meters are read monthly, and customers see only the imperfect price signal of a monthly bill rendered after electricity is used. Although larger commercial and industrial customers can be more price responsive, for many of them electricity is a small fraction of their cost of doing business and may receive little managerial attention. It takes time to develop the administrative rules and the technical capability to reduce consumption. As a result, most demand today is unable to respond to

²¹⁷For further discussion of these topics, see e.g., Steven Stoft, Power System Economics (IEEE Press, Wiley-Interscience, 2002) especially "Fallacy: The 'Market' Will Provide Adequate Reliability."

real-time prices because of insufficient price information, inflexible rate designs, and metering limitations.

464. The response of new generating capacity to price is slow because it takes time to plan, site and construct new electric power generating facilities. Development of a new power plant takes two to five years or more, depending on the type of plant and its location. It can take even longer to site the transmission lines needed to transmit the power to customers.

465. These factors together can lead to sustained periods of inadequate supplies, threatening the reliable operation of the bulk power system. Insufficient demand response to price and the slow supply response to price can combine to produce electricity shortages that not only threaten reliability but also can raise day-ahead and real-time market prices significantly.

466. Further, rushing to relieve inadequate regional supplies and reduce high regional spot prices may bias construction choices toward supply resources that can be constructed quickly, perhaps sacrificing long-term cost minimization, environmental concerns and fuel diversity goals. Most customers prefer spreading out resource capital costs over time to concentrating them into a peak period. A resource adequacy requirement accomplishes this.

b. Spot Market Prices That are Subject to Mitigation Measures May Not Produce an Adequate Level of Investment When a Shortage Occurs.

467. Customers object strongly to inadequate supplies—and high prices when supplies are inadequate—because electricity is essential for many uses and customers cannot turn to substitutes to reduce electricity demand. Electric power drives modern life, and there is significant societal disruption from even short supply interruptions.

468. For these reasons, customers want protection from the exercise of market power that may occur when supplies are short, and some form of market power mitigation is needed under these circumstances, as discussed in the market power mitigation section. However, market power mitigation may tend to suppress the scarcity price that would otherwise stimulate new resource development. As a result, investors may not develop adequate infrastructure—making the problem worse—unless there is a provision for resource adequacy. Such a provision helps customers by assuring adequate supplies and helps generation developers by creating a demand for resources in advance of electricity prices doing so alone.

c. Load-serving Entities Will Underinvest in Resources Needed for Reliability if They Can Depend on the Resource Development Investments of Others.

469. In an interconnected region, the failure of some market participants to secure sufficient long-term electricity resources can contribute to a shortage that affects reliability and spot market prices for all participants in the wholesale power market.

470. Under retail competition, load-serving entities competing for customers may compete on the basis of cutting the cost of forward contracting for resources unless they all are held to the same resource adequacy requirement. Without such a uniform

requirement, those suppliers that contract for reserves may lose market share, and those who do not may gain a market share – at least for a short period of time. For this reason, a load-serving entity has an incentive to minimize its own costs by procuring few or no reserves and relying on others to develop reserves. If the rules allow it, some load-serving entities will try to have the reliability benefit of adequate regional resources that other load-serving entities pay for or that uncontracted-for generation must offer pursuant to market power mitigation.

471. Severe power shortages lead to public insistence on government intervention.

Both historical practice and recent events indicate that during a shortage those load-serving entities that have reserves are required by government to share them with those that do not have reserves. There are at times state regulatory and gubernatorial requirements to protect customers from blackouts or high prices, a U. S. Department of Energy requirement for utilities to share power reserves in an emergency, or a Commission requirement to bid all available power into an organized spot market.

472. Some market participants depend on government intervention during severe shortages as an alternative to paying their share of the cost of developing adequate regional resources. As long as regional reserves are made available to all, a load-serving entity can reduce its own reserve resource costs and rely on the resources of others. The result is that all load-serving entities will tend to follow this strategy, leading to a

systematic underinvestment in resources needed for reliability.²¹⁸ The current physical configuration of the transmission grid often exacerbates this problem because it is often difficult to impose the results of one party's resource shortfall solely on that party. For example, if several competing load-serving entities serve customers in the same electrical neighborhood, it may not be technically feasible to curtail some of these customers and not others during a shortage.

473. These arguments persuade us to propose a long-term resource adequacy requirement in the Standard Market Design rule. A resource adequacy requirement provides for timely development of supply and demand response resources to assure regional resource adequacy. It helps smooths out the price swings of the electricity business cycle. A well-designed resource adequacy requirement supports competitive markets if it allows suppliers to compete to provide infrastructure and buyers to choose the infrastructure with the best combination of features such as cost, reliability, environmental effects, and service life.

²¹⁸This is the well-known "free rider" problem for public goods, those for which consumption cannot be limited to those who paid for them (such as parks and national defense) and that are available to all users even if only some users pay for them. See, e.g., Lee S. Friedman, *The Microeconomic of Public Policy Analysis*, Princeton University Press (Princeton, NJ 2002), which states at pages 597-598:

If their provision were left to the marketplace, public goods would be underallocated. The reason is that individuals would have incentives to understate their own preferences in order to avoid paying and free-ride on the demands of others. Thus, public goods provide one of the strongest arguments for government intervention in the marketplace: not only does the market fail, but it can fail miserably.

2. Basic Features of the Requirement

474. We propose to require, as set out in the proposed regulations, that an Independent Transmission Provider must forecast the future demand for its area, facilitate determination of an adequate level of future regional resources by a Regional State Advisory Committee, and assign each load-serving entity in its area a share of the needed future resources based on the ratio of its load to the regional load.

475. The Independent Transmission Provider must assure that each load-serving entity in its area acts to meet its share of the future regional needs—through self-supply, contracts to purchase generation, biddable demand or other demand response program. The Independent Transmission Provider must apply standards, discussed below, to audit the adequacy of the plans of load-serving entities to meet the future resource needs of its area. Moreover, the Independent Transmission Provider must check that resources are not double-counted by different load-serving entities. In a region with more than one Independent Transmission Provider, each Independent Transmission Provider must coordinate this checking responsibility with all the Independent Transmission Providers in the region.

476. If a power shortage occurs during which the Independent Transmission Provider is unable to satisfy demand in the spot market and also meet its reliability requirement for a minimum level of operating reserves, the Independent Transmission Provider must add a per-megawatt-hour penalty during the shortage to the price of energy taken from the spot

market by a load-serving entity that did not meet its share of the regional needs for that year.

477. Further, if the operating reserve level decreases to the point that the Independent Transmission Provider must curtail load, the Independent Transmission Provider must, to the extent possible, curtail the spot energy purchases of the load-serving entity that did not meet its resource adequacy requirement before curtailing the spot energy purchases of load-serving entities that did. The load-serving entity is subject to such first curtailment during a shortage only in the amount by which it falls short of meeting its share of the resource adequacy requirement for the year in which the shortage occurs.²¹⁹

478. If a shortage remains after all such first curtailments are completed and additional curtailment is necessary, the remaining loads of the first-curtailed load-serving entities and the loads of other load-serving entities that have satisfied their resource adequacy requirement would be curtailed under the same protocol. In this case the shortage may be attributable to certain load-serving entities of either type that, whether or not they may have met their resource adequacy requirement. We expect that those load-serving entities that are short of their own reserves would lose service ahead of those that are not short.

479. The approach to resource adequacy proposed here is intended to assure the development of both new supply and demand response resources. This approach focuses

²¹⁹ A load-serving entity that continues to take spot market energy despite the curtailment order of the Independent Transmission Provider would be subject to a very high penalty under the tariff.

on encouraging payment to fund construction of future resources instead of avoiding payment of a penalty for inadequate current resources as in some current programs. The forward-looking planning horizon provides time for market entry by new suppliers, which will help to check any market power among existing suppliers.²²⁰

480. This proposal is designed to complement, not replace, existing state resource adequacy programs. A vertically integrated utility satisfying a current state resource requirement that equals or exceeds its share of the resource adequacy requirement would not have to do anything more. For those states that have retail choice programs in which retail customers or their suppliers buy power from a multistate region, we intend this approach to provide for regional adequacy in a way that no one state alone may be able to accomplish.

481. The proposed approach is like the traditional reserve margin requirement imposed by states on monopoly utilities. It worked well during most of the last century to ensure adequate supplies, and is still in use in most states, especially states that have no retail choice program. However, because the traditional approach relies on individual utility plans and resources, it might not continue to work well in a region where utilities now rely on independent power producers in several states for new resources instead of their

²²⁰ A regional resource adequacy requirement should also provide substantial evidence of need for infrastructure to investors as well as to siting authorities. This should aid suppliers in acquiring financing and should facilitate siting decisions. An added benefit may be the ability to better predict, plan, and finance new transmission system facilities associated with these resource requirements.

own new generation. The traditional reserve margin requirement may also not work well in a region where some states have traditional monopoly utilities and others have retail choice because a shortages in one state can affect all states in the region.

482. To continue to rely on the traditional reserve margin requirement, it has to be adapted to have a regional focus and to fit with competitive procurement. We propose a resource adequacy requirement of this type.

483. The resource adequacy requirement proposed here is unlike that of the three Northeast ISOs. ISO-New England, the New York ISO and PJM each impose an obligation on load-serving entities known as an Installed Capacity (ICAP) requirement. The three requirements differ, but share some basic characteristics. We are reluctant to impose a national ICAP requirement, in part because of our concern about the effectiveness of the existing ICAP programs and in part because they were based on former voluntary tight power pools. The three ISOs play a strong role in administering the program, a role that may not suit regions without a history of tightly coordinated reserve sharing.

484. The basic features of the proposed requirement are set out next, including discussion of the demand forecast, the level of resource adequacy, the role of the load-serving entity, the load-serving entity's share of the regional resource adequacy requirement, the types of resources that can satisfy the resource requirement, the standards that each type of resource must meet, the planning horizon, enforcement of the requirement, and regional flexibility.

a. Demand Forecast

485. A Independent Transmission Provider would be required to do an annual demand forecast for its area. The forecast would look ahead for the time period needed to add new supply and demand response resources. We will refer to this time period as the planning horizon, a topic discussed further below.

486. Demand forecasts have long been used in the utility industry to determine the need for future resources and to plan new infrastructure investments. The Independent Transmission Provider may undertake a “bottom up” method of demand forecasting by adding up the demand forecasts of its component areas where they can be relied on.²²¹ This may be accomplished through a collaborative process with all stakeholders.

b. Level of Resource Adequacy

487. After the area's demand is forecast, the Independent Transmission Provider must assess whether the collective resource plans of load-serving entities in this area are adequate to meet the projected future peak need with allowance for adequate reserves. In today's more competitive environment, the effectiveness of single-utility supply forecasts may be reduced. Under open wholesale transmission access, regional patterns of energy flow can change quickly, making single-utility transmission planning difficult.

Generators sited in a utility's service territory, if not under contract, may export power to

²²¹A load-serving entity has an incentive to underestimate its future load if doing so would reduce its share of the resource adequacy requirement. For an analysis of bias in demand forecasts, see Mark Bock, "Analysts hunt for bias in NERC forecasts," Electric Light & Power, July 2002.

another area or region. Single-utility forecasting is also more difficult today because power market information is considered very sensitive. Competitive suppliers are reluctant to share this information with a utility that is a potential competitor. A regional assessment of regional supply adequacy by one or more independent entities in the region would help overcome these difficulties.

488. Further, close coordination is needed between those planning generation and transmission because the location of planned generation affects the location of planned transmission and vice versa, and an Independent Transmission Provider (or a group of Independent Transmission Providers acting collectively in a region with more than one Independent Transmission Provider) is in the best position to coordinate these planning functions.

489. Once the future level of supply and demand resources is determined, the region must assess whether this level is adequate. This requires a regional determination of the appropriate level of resource reserves, for example, whether the reserve margin (if reserve margin is the region's measure of resource adequacy) should be 12, 15, 18 percent, or another level. We seek comment on and encourage regional discussion of appropriate planning targets in energy-limited areas, specifically on how to incorporate volatility of annual hydropower supply.

490. Each region should take its own characteristics into account when determining the appropriate level, subject to a minimum level of resource adequacy for all regions discussed below. This determination has been made by load-serving entities under the

oversight of the states, and we want this state oversight to continue. We propose that the level should be set by a Regional State Advisory Committee.²²² States in the region should have this strong role in determining the level of resource adequacy because a higher level provides greater reliability and also incurs higher costs that affect most retail customers. State representatives are in the best position to determine on behalf of retail customers the trade-off between the cost to the customers of extra generation and demand response reserves and the difficult-to-quantify benefits to the customers of increased reliability and reduced exposure of the region to the effects of a power shortage.

491. We will require the Independent Transmission Provider (or the several Independent Transmission Providers in a region with more than one such Provider) to provide a forum and assistance to the Regional State Advisory Committee to establish the appropriate level of resource adequacy for the region. Because many Independent Transmission Providers encompass more than one state (or province), the Independent Transmission Provider's role as a facilitator will be helpful in establishing the regional reserve level.

492. However, we ask for comment on what fallback provision should be employed if the Regional State Advisory Committee does not reach agreement on the appropriate level of resource adequacy. We believe that having different reserve levels in different

²²²See the following section, State Participation in RTO Operations, for a discussion of the composition of the advisory committee.

states in the same region maintains the problem of some customers relying on the reserves of others.

493. We are concerned that the requirement be set so that the Independent Transmission Provider can operate the interstate transmission system reliably with real-time operational resource adequacy. We are also concerned that inadequate resources could lead to poor market liquidity and even shortages with sustained high wholesale power prices. For these reasons, we propose to adopt a 12 percent reserve margin²²³ as a minimum regional reserve margin for all regions with the understanding that this is low by traditional generation adequacy standards and that the Regional State Advisory Committee in each region may set this number higher for the region to achieve greater reliability. We

²²³The reserve for a period is the amount of resources expected to be available during the period less the forecast peak load during the period. The reserve margin is the ratio of the reserves to the forecast peak load during the period, expressed as a percentage. A region may use another measure of adequacy as long as the minimum level is the arithmetic equivalent of a 12 percent reserve margin. For example, many use capacity margin, which is the ratio of the reserves to the amount of resources expected to be available during the period, expressed as a percentage. A capacity margin of 10.7 percent is the same as a reserve margin of 12 percent. Some may measure adequacy with a loss-of-load probability, called LOLP, which is a statistical measure of the expected total time during a period that generation will be unable to meet load. The common U.S. standard is one day in ten years, which means that the sum of the hours (or fractions of hours) during a ten-year period when generation is expected to be short is 24 hours. Reserve margin cannot be translated directly into LOLP without studying a particular system. For example, an area served by a few large generators is more vulnerable to a shortage caused by an outage of one or two large generators than a similar area served by many smaller generators. The area with a few large generators may need a larger reserve margin to achieve the same LOLP. A general rule-of-thumb for a large U.S. utility system is that an LOLP of one-day-in-ten-years is achieved with a reserve margin of about 18 percent.

selected a 12 percent reserve margin as a minimum in that it is two-thirds of the typical historical reserve margin target of 18 percent for large utilities.²²⁴ We emphasize that most utilities historically used a reserve margin well above 12 percent. This 12 percent reserve margin is intended to be a safety-net level in planning for reliable future transmission and market operations and not to be the target reserve level for the region that should be established by the Regional State Advisory Committee.

c. Load-serving Entities

494. Each load-serving entity must satisfy a portion of the regional resource adequacy requirement. Load-serving entity here means any entity that uses transmission in interstate commerce to provide power to load, whether a traditional distribution utility or an energy service supplier that aggregates retail loads under a retail access program.

495. A large retail industrial or commercial customer that has retail access rights and buys power directly from suppliers is also considered a load-serving entity. If it does not buy power from another load-serving entity but uses the interstate grid to buy power directly from a supplier, it too would be required to meet its share of the resource adequacy requirement. As for other load-serving entities, their reserves may include the ability to reduce their own demand on the grid.

496. A load-serving entity may choose a higher level of reliability by developing more supply or demand response resources than required. Further, a load-serving entity may

²²⁴The target level of these reserves, often called planning reserves, is not the same as the operating reserve level, a subject treated further below.

choose greater reliability and price assurance by procuring additional reserves for its own use. In particular, customers in a load pocket that is served by a few large generating units may need a higher reserve margin to have the same level of reliability as customers outside a load pocket.

d. Load-Serving Entity's Share of the Regional Resource Requirement

497. Once the future regional requirement is determined, each load-serving entity's share of the regional requirement must be determined. Meeting a regional resource adequacy level does not assure that every part of the region has adequate resources if there are internal transmission constraints or if resources are counted that may be sold outside the region, retired before needed, or otherwise made unavailable. For these reasons, it is important that resources not be considered merely regional but be associated with and committed to particular load-serving entities.

498. We request comment on two methods for determining each load-serving entity's share of the regional requirement. One is to allocate the future resource adequacy needs to loads based on each load's forecasted future demand. For example, if the load forecast is for three years ahead and a particular load is growing faster than the regional average, its share of the adequacy requirement could be based on its forecast load ratio share for three years ahead, not on the present load ratio share. This method assigns more adequacy responsibility – and cost – to faster growing loads. However, if the Independent Transmission Provider's forecast is made through a "bottom up" method that

adds up individual load forecasts, it must rely on each load to report its growth rate accurately. This approach creates an incentive for loads to understate their growth to lower their resource costs.

499. The other method is to allocate the future adequacy requirement to loads based on each load's most recently documented load ratio share. This method is less subject to manipulation. However, an area with a slow load growth located within a region of generally high load growth may subsidize the high reserve needs of its neighbors.

500. We ask for comment on which of these two methods the Commission should choose in the Final Rule. Alternatively, we ask whether this issue should be left to regional determination.

501. Once each load-serving entity's share of the regional adequacy requirement is determined, the Independent Transmission Provider must inform each load-serving entity of its share. It must require each load-serving entity to report and document how it plans to meet its adequacy requirement.

502. The time available to the load-serving entity from being informed of its resource share to having to report to the Independent Transmission Provider must be adequate to allow it to develop arrangements for meeting future resource needs. We ask for comment on how much time is needed for these purposes.

e. Resources That Can Satisfy the Resource Needs

503. Each region's resource adequacy requirement could be satisfied by a combination of generation, transmission, and demand response infrastructure.

(1) Generation and Transmission

504. The supply requirement could be satisfied by self-owned generation, local distributed generation, or firm bilateral contracts for power that are backed by specific generating units (or a portfolio of designated generation units). The firm bilateral contract could be either a forward contract for the purchase of power or an option to purchase energy under specified shortage or price conditions, as long as the firm contract is backed by specified generating units.

505. In any of these cases, the generator must be committed to supply power to the load-serving entity, at least under certain conditions. Self-owned generation that is committed to another load-serving entity, unless it can be recalled during a shortage, would contribute to the other load-serving entity's requirement, not the requirement of the load-serving entity that owns it. Generation under contract must specify that the generator will be available to the load-serving entity – or at least to the market that the load-serving entity participates in – under conditions set out in the contract. These conditions, discussed further below under generation standards, must be adequate to meet the region's need for reserve resources.

506. The firm contract would be for a forward-looking period that would at least cover the planning horizon, which (as discussed further below) would be selected regionally and should be based on the time needed to develop new resources in the region. The load-serving entities must also demonstrate that future use of the designated resources is

physically feasible and, in particular, that transmission is or will be available to deliver energy from a generator to the load-serving entity that claims it in its resource plan.

(2) Demand Response

507. Allowing demand response infrastructure to satisfy the requirement removes bias toward exclusive reliance on new generation to meet regional needs. Better demand response to high prices when a shortage condition approaches will lower demand and reduce the use of high-cost power resources. Demand response will help ensure reliability, prevent a shortage that could produce a curtailment, act as a check against market power, and provide a yardstick for the value that buyers place on supply.

508. Biddable and interruptible load can satisfy the resource adequacy requirement as well as generation.²²⁵ A load-serving entity that does not want to pay for generating reserves can substitute a demand response alternative to meet its resource adequacy requirement. Under some state programs, the larger retail customer may be rewarded for reducing its electric use in addition to enjoying a reduced bill for reduced consumption. Several states have this type of biddable load reduction; it is one way to allow the customer to determine how much it is willing to pay for power. Further, competitive energy service suppliers can compete for load by offering lower rates to customers who agree to participate in demand response programs such as remote air conditioner cycling,

²²⁵The traditional reliability reserve margin allows interruptible load to be counted equally with generation resources, with some exceptions.

aggregate building load management, and other proven demand response and load management options.

3. Resource Standards

509. The Independent Transmission Provider must determine if each load-serving entity's planned resources meet certain standards. The resources must meet the standards to count toward satisfying the entity's share of the regional resource requirement. Both generation and interruptible or biddable load must meet standards to satisfy the requirement.

510. We propose here certain minimum standards for comment. We also are considering in the Final Rule to ask the North American Energy Standards Board (NAESB) to develop more detailed standards for determining whether resources satisfy the resource adequacy requirement, and we seek comments on this approach.

a. Generation Standards

511. Generation must be owned by or under contract to the load-serving entity and committed to meet the resource needs of the load-serving entity at least during certain conditions such as an operating reserve shortage. The Independent Transmission Provider must be satisfied that the generation is physically feasible; that is, the generating units are capable of generating the power planned, and enough transmission is available to deliver the power from the generating station to the particular load. The generating units under contract must be real and specific generators. This is so that only real generation that can avert a supply shortage is counted and so that its transmission over the

grid can be assured. For example, it does no good for a load on Long Island to claim a generator in western New York as a resource if the power cannot be delivered to Long Island during a Long Island shortage.

512. Because the purpose of this requirement is to encourage the development of new resources including new generation, generation under contract for development within the planning horizon should satisfy the requirement. Should the Commission specify the contract content needed to rely on generation under development? If so, should we refer this matter to NAESB to determine the content?

513. For these reasons also, a contract with a marketer to deliver power at a future time from unspecified sources cannot satisfy the requirement. The purpose here is not to transfer financial risk for nonperformance to a marketer but to ensure performance, that is, to ensure that enough actual, deliverable generating capacity is available or developed at satisfactory locations to avert a future shortage. However, a forward contract with a marketer that is linked to specific generation and demonstrates transmission adequacy would satisfy the requirement. We ask for comment on whether we should allow a liquidated damages contract for power from unspecified sources to be included in the resource adequacy plan, and also on whether we should allow a load-serving entity that initially fails to satisfy the resource adequacy contract, but later brings in new resources under a liquidated damages contract for the amount of its resource deficiency, to avoid the penalty price and first curtailment in the spot market during a shortage.

b. Transmission Standards

514. Generation must be deliverable to satisfy the requirement. A Congestion Revenue Right for the appropriate year is one way to satisfy this requirement. We propose to adopt a practice (used in PJM) that allows a resource owner to pay for the development of adequate transmission to deliver its energy to a load and then to sell its Congestion Revenue Rights while still satisfying the requirement that its generation be deliverable. Should a commitment by any load-serving entity to pay congestion costs no matter how high also satisfy the requirement? If so, how should the Independent Transmission Provider respond if the sum total of all such commitments exceeds the available capacity of a bottleneck interface?

515. A robust transmission system with few constraints may allow a load to rely on generation and demand response reserves that are farther away than if the transmission system is weak. Supply reserves that are not deliverable to the load claiming them when needed cannot be counted as satisfying that load's reserve requirement.

516. For transmission as well as for generation and demand response, the purpose of this requirement is to encourage the development of least-cost resources, which may include new transmission needed to access existing or new generation. We believe therefore that planned transmission with full siting approval and completion expected within the planning horizon should satisfy the adequacy requirement.

c. Demand Response Standards

517. Demand response must also be verifiable to satisfy the adequacy requirement. The Independent Transmission Provider must have confidence that the demand response

resource will be able to contribute when called on during a shortage. Demand response may be obtained through biddable demand reduction, interruptible load, or other dependable load management program. Distributed generation that is interconnected with a customer, a load-serving entity, or an energy services company, although it is technically generation and not demand response, can also be used by a local distributor to reduce the demand that the distribution system places on the grid. With biddable demand reduction, certain loads will be assured of dropping off the system at known price levels; the amount of load dropped should increase with the price.

518. With interruptible load, a customer pays a lower power price year round but will be interrupted under defined shortage conditions; the load is subject to a simple on-off criterion. An important feature of this proposal is that the load-serving entity plan that depends on interruptible load to meet its resource adequacy requirement must be capable of being implemented. The Independent Transmission Provider may require, for example, that the load-serving entity install equipment that gives it direct control over the loads of the customers that are subject to the interruption. We recognize, however, that installation of such equipment may be too costly or otherwise impractical in some situations. In that case, the load-serving entity must have a satisfactory arrangement for implementing its interruptible load program under the instructions of the Independent Transmission Provider.

519. If load in an area "buys" demand reduction from another area (in effect buying some of that other area's freed-up generation), the transmission needed to deliver the freed-up generation to the load that relies on it must be available.

4. Planning Horizon

520. The purpose of a forward-looking resource adequacy requirement is to create a demand for new resource entry in advance of a shortage so that enough supply construction and demand response infrastructure installation are begun in time to avert the shortage. The planning horizon for each region is the number of years ahead for which the Independent Transmission Provider must forecast annually its area's load, as well as the number of years ahead for which load-serving entities must show that they have adequate resources. For example, the Independent Transmission Provider could forecast its area's peak load three years from the present and require that each load-serving entity in its area have acceptable plans today to have enough resources three years from now to meet the forecast peak with a reserve margin of 12 percent. In this example, the planning horizon is three years and the reserve level is the minimum 12 percent.

521. The choice of the planning horizon affects the lead time for construction and the duration of forward contracts that can satisfy a resource adequacy requirement.²²⁶ The traditional state-required electric company planning horizon was 10 to 20 years. The

²²⁶For example, forward-contracting for supply with one-year contracts that begin today and end after one year would not satisfy an adequacy requirement with a three-year planning horizon. A one-year contract for the third year forward would satisfy the goal for that year.

horizons were established when the industry relied on new large hydroelectric, coal, or nuclear facilities to meet growing load, and these facilities could take 10 or more years to site and construct. Today, most new resources are planned and developed over a much shorter time frame, in part because of the reliance on low cost natural gas. However, this planning horizon could change again if natural gas were no longer the main fuel of choice.

522. Because the planning horizon should be no less than the time frame for developing new resources and development times vary from region to region, the planning horizon can depend on that region's reliance on coal, gas, wind, hydropower or new demand-response technology for new supply. This argues for allowing each region to determine its own appropriate planning horizon.

523. We propose to make the planning horizon a matter for regional choice. Regions should consider several factors in selecting the planning horizon. Most important, the planning horizon chosen should not be so short that it fails to motivate and achieve construction of generation and demand response resources in time to avert a shortage. Greater fuel diversity may be achieved with a longer planning horizon. If the horizon is short, two years for example, load-serving entities may have an incentive to select resources that can be developed in two years or less, such as peaking units and some other gas-fired generators. A longer planning horizon allows time for development of other resources such as coal-fired generation, hydroelectric resources, and some advanced demand response programs. Load-serving entities in retail choice states would benefit

from a shorter planning horizon because it would reduce their business risk associated with demand forecast error. Also, they may not want to enter into bilateral contracts for supplies for a time period that is longer than the duration of their contracts with their customers.

524. We propose to have the Regional State Advisory Committee determine the planning horizon for the region. The Independent Transmission Provider (including each Independent Transmission Provider in a region with more than one Independent Transmission Provider) must provide information and support to the Committee, as requested, to help it to determine the region's planning horizon. We request comment on how to resolve any lack of consensus within the Committee regarding the appropriate planning horizon. We also ask for comment on whether the Commission should establish limits on the region's choice of planning horizon, such as at least three years and no more than five years.

525. We also ask for comment on whether to have a resource adequacy requirement before the end of the first planning horizon period. For example, if the horizon is three years, should there be a requirement for resource adequacy in the first two years?

5. Enforcement

526. Here we explain in more detail our proposal to enforce the resource adequacy requirement, along with some alternative enforcement procedures, and ask for comment on the most effective enforcement method.

527. Unlike some ICAP requirements, the approach adopted here does not require a load-serving entity to pay a penalty in the near term for failure to have adequate future resources. Our proposed approach relies primarily on two enforcement mechanisms: (1) a Commission-set tariff penalty imposed on a load-serving entity that threatens reliable transmission operation by taking energy from the spot market during a shortage in a year for which it fails to meet its resource adequacy requirement, and (2) a Commission requirement that the spot market electric service of such a load-serving entity must be curtailed first when the shortage that is severe enough to require that some customers be curtailed. Each of these mechanisms, the penalty rate and the load curtailment, would occur at the end of the planning horizon, not the beginning.²²⁷

528. The first mechanism applies during a power shortage in which the Independent Transmission Provider is unable to satisfy demand in the spot market and also meet its reliability requirement for a minimum level of operating reserves.²²⁸ As a shortage

²²⁷For example, if the planning horizon is three years, a demand forecast would be made in 2004 for the year 2007. The Independent Transmission Provider would assess the adequacy of resources for 2007 and allocate the resource adequacy requirement for 2007 among the load serving entities. The entities would submit to the Independent Transmission Provider in 2004 their plans to meet their share of the 2007 resource adequacy requirement. An entity fails to submit in 2004 a satisfactory resource plan for 2007 would not be subject to the penalty rate or be among the first curtailed during a shortage in 2004 but would be subject to the penalty rate and be among the first curtailed during a shortage in 2007. Next year, in 2005, the same process repeats: the Independent Transmission Provider would forecast demand in 2008, and so on.

²²⁸Operating reserves are generation and demand response resources needed to keep the system in balance, follow changes in load, and make up for a "contingency" such
(continued...)

develops, price is expected to increase in the spot energy market. A load-serving entity that is short on self-generation, bilateral contracts (including affiliate generation and call contracts), and demand response resources will be dependent on the spot markets to meet its resource needs. The rising price in the spot market is, of course, a principal incentive for the load-serving entity to develop adequate supply and demand resources. If shortage conditions develop to the point where the Independent Transmission Provider cannot serve all load and maintain the minimum level of operating reserves, it must take some action to maintain reliable operation. Some load must be given either an economic incentive to exit the spot market or an order to stop taking power from the spot market. We propose that these measures be applied first to the load of the load-serving entities that did not meet their share of the resource adequacy requirement. However, the load-serving entity is subject to a penalty and first curtailment during a shortage only for spot

²²⁸(...continued)

as the loss of the largest generating unit or of a major transmission line that delivers more power than any one generating unit. The North American Electric Reliability Council and the regional reliability councils set rules regarding the minimum operating reserves that must be maintained by the system operator for reliable operation. The rules are expressed in a formula so that the value of the minimum operating reserves changes during the day with load conditions and with the sources of supply. Typically, for a large utility, the minimum operating reserves are in the range of 5 to 8 percent of load, but this can vary significant with changing conditions. An operator that operates with less than minimum operating reserves threatens not only its own reliable operation but the reliability of its electrical neighbors.

energy purchases²²⁹ and only in the amount by which it falls short of meeting its resource adequacy requirement.

529. Specifically, we propose that during such a shortage the Independent Transmission Provider must add a per-megawatt-hour penalty price to the price of energy taken from the spot market by a load-serving entity that did not meet its share of the regional needs for that year. This rate would apply only to spot energy purchases, not to power received from the load-serving entity's self-generation or bilaterally contracted energy. However, it would apply to spot market energy sales needed to correct for imbalances associated with energy from these sources. We would set the penalty price high enough that we do not suggest that failing to meet a resource adequacy requirement and paying a penalty rate is an acceptable alternative to developing new resources, which would be the case if the paying the penalty appears to be less costly over time.

530. The penalty price would increase in stages as the shortage becomes more severe. For example, the penalty price could be \$500 (in addition to the spot market energy price)

²²⁹These actions apply to spot energy purchases only. In the event that the load-serving entity that failed to meet its share of the resource adequacy requirement has adequate supply and demand resources outside the spot market available to it at the time of the shortage, the Independent Transmission Provider would continue to provide transmission to support delivery of these resources. This proposal gives deference to the ownership and contractual right to use self-generation, bilateral contracts, and demand response resources, and it encourages the development of such resources during the planning horizon period by those entities that failed to plan adequately at the beginning. It also discourages contracting with unreliable resources to meet the resource adequacy requirement because each load-serving entity must actually rely on its resources to meet its resource needs.

when operating reserves are just below the minimum level, \$600 when operating reserves are more than 1 percent below the minimum level, \$700 when operating reserves are more than 2 percent below the minimum level, and so on. We ask for comment on having such a graduated penalty and the appropriate penalty rates.

531. This first enforcement mechanism provides a price-based mechanism to enforce a resource adequacy requirement and to restore the transmission system to a reliable condition. Most system operators – and their regulators – treat load curtailment (voltage reductions and blackouts) as a last resort measure, and operators may violate the reliability rule for minimum operating reserves rather than implement a load curtailment to satisfy the minimum operating reserve criterion.²³⁰ We believe that the penalty price should be set high enough to bring about voluntary load reduction by a load-serving entity and thus restore the system to a reliable condition.

532. The second enforcement mechanism is applied when the operating reserve level decreases to the point that some load must be curtailed.²³¹ The spot energy purchases of

²³⁰We will not overturn this practice by requiring curtailment of load immediately to restore the minimum operating reserve level. Some regions have a regional policy of taking action to reduce voltage or shed load only when operating reserves fall to some fraction, such as three-fourths or three-fifths, of the minimum operating reserve requirements of the reliability organizations.

²³¹Regional practice will determine when load must be curtailed to maintain reliable operation. Operators may continue to follow their existing reliability practices: those that do not curtail service immediately when the operating reserve level goes below the minimum must impose the penalty price on resource-deficient load-serving entities. However, it is not our intent to require an operator to violate a reliability rule by
(continued...)

that load-serving entity load would be reduced by the amount of its resource deficiency and consequently some of its customers would be curtailed before the loads of other load-serving entities.²³²

533. In support of this second mechanism, we will require the Independent Transmission Provider to inform the load-serving entity's state regulatory authority²³³ if the load-serving entity fails to submit a satisfactory plan for adequate future resources, thereby exposing its customers to possible penalties and future first curtailment during a shortage. Our intent is to rely on the traditional state role of enforcing a load-serving entity's reserve obligation. We believe that in most cases the state regulatory authority would prefer to have the load-serving entity meet the adequacy requirement as a condition of doing business in the state, rather than expose its retail customers to first

²³¹(...continued)

providing service with a penalty price instead of enforcing its reliability rule through load curtailment. We believe that a high penalty price may result in the needed load reduction. Whenever the operator must curtail load to maintain reliability, it should do so. Our requirement goes to which load must be curtailed first when curtailment of load is necessary, not to when curtailment becomes necessary.

²³²An individual load-serving entity may run short of planned-for resources when its region is not experiencing a regionwide shortage, for example, because of a combination of high demand on its own system and unplanned outages of its own resources. In this case it is not required to be curtailed because that load-serving entity may procure additional supplies from the short-term or long-term bilateral market or from the spot market. Since the region is not short, others are likely to sell power, including perhaps a portion of their reserves on the basis that the reserves can be recalled if a regionwide shortage occurs.

²³³In this section, the term "state regulatory authority" includes the retail rate regulating authority for load-serving entities not regulated by a state utility commission.

curtailment. The state regulatory authority may wish to consider any decision of a load-serving entity not meet its resource adequacy requirement. It may want to ask the load-serving entity to identify which of its customers will be subject to first curtailment if the region is short of power.²³⁴

534. If the Independent Transmission Provider does not have direct control of the circuit equipment needed to implement a curtailment and relies on the load-serving entity to follow its instructions to implement a curtailment, the load-serving entity would be subject to a severe penalty for the unauthorized taking of power from the spot energy market because this jeopardizes grid reliability. We propose to charge the applicable Locational Marginal Price plus \$1000/MWh for all unauthorized energy taken following an instruction to implement curtailment.²³⁵ We also seek comment on whether the \$1000/MWh penalty would be sufficient to deter unauthorized taking of energy and, if these penalties are paid, who should receive these revenues.

535. We believe that load-serving entities, under these enforcement provisions and under the oversight of state regulatory authorities, will meet their resource adequacy requirement and not be subject to these curtailment penalty and first curtailment

²³⁴Any necessary curtailment action, whether a first curtailment or any subsequent curtailment action may have to satisfy applicable state or local rules for ensuring that essential retail services (such as police, hospitals, fire stations) are maintained.

²³⁵See SMD Tariff, Appendix B, Section I.5.

provisions at all. If most meet the requirement as we expect, shortages and first curtailment of any that do not should occur infrequently.

536. Having presented our enforcement proposal, we suggest variations of this proposal and ask for comments on these alternatives. As mentioned, under our proposal the penalty rate or load curtailment would occur at the end of the planning horizon, not the beginning. However, we ask for comment on this approach compared to an alternative approach that may provide a more immediate and effective incentive to a load-serving entity to take action to provide for future resources well in advance of facing a penalty or first curtailment. This is to impose a penalty on the load-serving entity immediately (that is, in year 2004 to continue the example in an earlier footnote) if it fails to submit a satisfactory plan to meet its 2007 resource adequacy requirement. We did not propose this option as our first choice because it has some of the unfavorable features of some ICAP programs that focus more on avoiding immediate penalties than on motivating long term resource development. However, we ask for comments on the merits of this alternative approach.

537. As presented, the Independent Transmission Provider audits the plan of each load-serving entity only at the beginning of the planning period (in 2004 in the example above). We are concerned that a load-serving entity may submit a satisfactory plan but fail to fully implement the plan. The proposal permits but does not require the Independent Transmission Provider to audit each year the progress of the load-serving entity in implementing its plan, and we ask whether we should explicitly require this. If

the load-serving entity's progress is unsatisfactory, should the Independent Transmission Provider find that it fails to satisfy its resource adequacy requirement? If the load-serving entity implements its plan but some of its resources fail to perform when needed during a shortage, should that load-serving entity, in addition to having a greater need for spot market energy at a presumably higher spot market price, also be subject to either of the enforcement mechanisms set out above?

538. Another feature of our proposal is that it would not affect electric service from the self-generation and bilateral contracts of a load-serving entity that fails to meet its resource adequacy requirement (except that it would be subject to a penalty price during a shortage for balancing energy in the spot energy market). We ask for comment on whether this proposal unduly weakens the incentive to develop regional resources and whether, in the alternative, the Independent Transmission Provider should first curtail service to the load serving entities that failed to meet their share of the resource adequacy requirement, including transmission service from resources acquired outside the spot market, freeing up those resources for the use of those that planned adequately.

539. Finally, our proposed enforcement mechanisms are designed to create an incentive to avoid a future penalty or first curtailment. During the public outreach process for developing this proposed rule, some commenters recommended a stronger Independent Transmission Provider role in compliance with a mandatory resource adequacy requirement. One proposal is for the Commission to require the Independent Transmission Provider to procure resources on behalf of load-serving entities that fail to

meet fully their requirement and charge them for the cost of the resources.²³⁶ Another is for us to require the Independent Transmission Provider to either (1) calculate an expected capacity deficiency and purchase the call options necessary to meet the adequacy requirement on behalf of the load-serving entities, allocating costs pro rata, or (2) require load-serving entities to purchase reserves at the price produced by an Independent Transmission Provider-run auction.²³⁷

540. These approaches have advantages as well as disadvantages. Among the advantages are that they provide a greater assurance of achieving adequate resources and avoid the possible pitfalls of applying penalty rates or first curtailment. Among the disadvantages are that they take away one demand response option, namely curtailment, from the range of policy choices. Also, the latter approaches appear to require the Independent Transmission Provider to take a position in the capacity market, which places the Independent Transmission Provider in a role that may be incompatible with its independence.²³⁸

²³⁶See, e.g., Electricity Market Design and Structure, Docket No. RM01-12-000, comments of Reliant Resources, Inc., filed May 3, 2002, at pages 11-12, in Docket No. RM01-12-000.

²³⁷See, e.g., Electricity Market Design and Structure, Docket No. RM01-12-000, comments of Mirant Americas, Inc. and Mirant Americas Energy Marketing, L.P. filed May 2, 2002.

²³⁸They also raises difficult jurisdictional questions, in that Commission has regulated the seller's side of wholesale transactions and the states have regulated the buyer's side. Under some of these proposals, we would have to distinguish a transmission penalty levied by the Independent Transmission Provider for a load-serving
(continued...)

541. What is the effect of these alternate enforcement mechanisms on the incentives and business risks of the load serving entities in the region? Is there another enforcement mechanism that is both appropriate and effective?

6. Regional Flexibility

542. We propose to apply the requirement set out above to all regions, including regions that already have an ICAP requirement that has been previously approved by the Commission. This requirement would replace the current ICAP program.

543. Some regulators, customers, and market participants have expressed dissatisfaction with the ICAP models presently in place. Some customers view ICAP as an added cost with no tangible benefits; they assert that the commodity being traded has little value because customers are paying for installed capacity but not receiving any greater assurance that generation adequacy is maintained. Some commenters say that, in some ICAP programs, a generator can receive an ICAP payment and later be released from the ICAP obligation for a relatively small penalty to sell its capacity in another market with a high wholesale price.

544. Existing local generators are said to have preferential ability to participate in the ICAP market. The ICAP payment goes to the existing generators and does not necessarily lead others to enter the market to increase capacity. Depending on how the

²³⁸(...continued)

entity's failure to procure the resources needed to maintain transmission security from a Commission-enforced mandatory purchase of reserves by the load-serving entity.

ICAP rules are designed, existing generators may be able to exercise market power, forcing up ICAP prices. In some markets, trading has been so thin at times that there is a question about whether there is a competitive market price.

545. In some such cases, the ISO has intervened to set the price administratively, and market participants are concerned that the price does not reflect the forward value of generating capacity. Some contend that prices in the spot markets and bilateral markets, including long-term forward contract markets, appear to be not well correlated with ICAP market prices.

546. The generators object to ICAP price controls. Some power generators see short-term ICAP payments as providing inadequate assurance of capital cost recovery to motivate new investment. They prefer longer-term contracts to ensure that their investment costs will be recovered.

547. Finally, many parties object that ICAP focuses on power generation, ignoring the potential of demand response.

548. Although we propose that every region must adopt our approach, this approach offers significant regional flexibility. Our approach allows each region to set its own level of resource adequacy, set its own planning horizon, and select from a combination of supply and demand response resources for meeting its needs.

549. Our proposal permits but does not require a region to have its Independent Transmission Provider establish a market for acquiring and trading adequate resources. We believe that the bilateral market and other means can be adequate for acquiring and

trading resources. Nevertheless, we ask for comment on whether, under the approach to resource adequacy proposed here, we should require an Independent Transmission Provider to create a market to facilitate load-serving entities meeting their resource adequacy requirement efficiently.

550. Despite the flexibility of our proposed approach, regions with a historical reliance on a tight pool for sharing reserve may argue for a continuation of some form of ICAP program. We ask for comment on how existing Commission-approved ICAP mechanisms can be transitioned and modified so as to be made consistent with our resource adequacy proposal here without disrupting financial commitments made under existing rules. What are the disadvantages of particular elements of the ICAP approach that should be avoided in the approach proposed here? Do any of the enforcement proposals or alternatives discussed above re-introduce any such disadvantageous elements?

K. State Participation in RTO Operations

551. States have an important role in the process of creating and sustaining an efficient competitive wholesale market for electricity. The Commission has already established state-federal RTO panels as a forum for the Commission and state commissioners to discuss issues related to RTO development. However, there currently is not a formal process for state representatives to engage in a similar dialogue with the independent entity that will operate the electric grid under Standard Market Design. Therefore, the

Commission is proposing to establish a formal role for state representatives to participate on an ongoing basis in the decision-making process of these organizations.

552. We envision that the Independent Transmission Provider that operates the grid would have a Regional State Advisory Committee. The Regional State Advisory Committee should be formed and should have direct contact with the governing board, in a manner which recognizes its public interest responsibilities, and be designed to provide the board as well as market participants and the Commission with a consensus view from states in the area. The specifics of how this advisory committee would be formed and operate would be decided on a regional basis. This coordinated oversight will ensure fulfillment of federal public interest responsibilities in a manner that includes the views of states throughout the region. In this regard, we also encourage the participation of Canadian provincial authorities in this process.

553. We take note of the recent report by the National Governors' Association entitled "Interstate Strategies for Transmission Planning," which recommends establishing "Multi-State Entities" to facilitate state coordination on transmission planning, certification, and siting at a regional level.²³⁹ The report recognizes the critical role states currently play in siting as well as the need to address regional needs. The institution we propose here appears complementary to the National Governors Association's recommendation. In fact, it may be useful to have a single Regional State Advisory Committee rather than

²³⁹Available in
http://www.nga.org/center/divisions/1,1188,C_ISSUE_BRIEF^D_4110,00.html

separate committees for siting and other issues. We seek comment on whether there should be a single Regional State Advisory Committee, or separate committees for siting and other issues. We also seek comment on how the state representatives should be selected (e.g., whether the governor should select them or some other process should be used).

554. The Regional State Advisory Committee may work with the regional transmission organization to seek regional solutions to issues that may fall under federal, state, or shared jurisdiction, which may include but are not limited to:

- a. Resource adequacy standards;
- b. Transmission planning, expansion;
- c. Rate design and revenue requirements;
- d. Market power and market monitoring;
- e. Demand response and load management;
- f. Distributed generation and interconnection policies;
- g. Energy efficiency and environmental issues;
- h. RTO management and budget review.

Further duties may evolve with the development and operation of the regional councils.

555. As discussed, the Commission is proposing to require that the independent entity that operates the markets under Standard Market Design will have a Market Monitoring Unit (MMU). The MMU will be required to report directly to the Commission and the independent governing board of the Independent Transmission Provider. The MMU

should also provide its reports directly to the Regional State Advisory Committee.

Finally, because of the regional nature of these organizations, there are many new issues involving rate design and revenue requirements. We believe that the Regional State Advisory Committees can bring a valuable regional perspective to these issues and should play a role in deciding these issues in partnership with the Commission. Once the advisory committees are established, we intend to work with them to establish protocols for deciding these regional rate issues. Additionally, the Independent Transmission Provider will be required to develop regional plans for transmission planning and expansion. We believe this is also an area where the Regional State Advisory Committee can bring a valuable regional perspective and should be consulted in developing these regional plans.

L. Governance for Independent Transmission Providers

556. The Commission has previously recognized the importance of independent governance of regional organizations in both Order No. 888 and Order No. 2000. In Order No. 888, the Commission required that ISO governance be structured in a fair and non-discriminatory manner and that the ISO be independent of any individual market participant or any one class of participants. The Commission also required that the ISO's rules of governance should prevent control, and appearance of control, of decision-making by any class of participants. Order No. 2000 built upon and extended this independence requirement to RTOs. In Order No. 2000, we reaffirmed our commitment to independence as a bedrock principle for regional organizations, and in this rulemaking

we find that our commitment to independence also is critical to the successful implementation of Standard Market Design. Compliance with the independence requirement of Order No. 2000 is based on the independence of the Board of Directors and all employees of the RTO. The governance requirements for the Board of Directors is critical to ensuring that the RTO is independent and that the RTO's interests are aligned with the interests of the market as a whole rather than with particular market participants of classes or market participants. While we did not mandate detailed governance requirements for RTO boards in Order No. 2000, we stated that we would review on a case-by-case basis the RTO governance proposals and judge them against the overarching standard that the RTO's decisionmaking process must be independent of individual market participants and classes of market participants. We also required an audit of the independence of an ISO's governance process two years after its approval as an RTO.²⁴⁰ 557. The Commission has considered on a case-by-case basis whether individual RTO proposals satisfy the Commission's requirements for independence.²⁴¹ We have required changes where they did not.²⁴² However, we are concerned that the lack of more definitive guidance from the Commission on governance may be hindering the development of larger RTOs. Also, we are concerned that the existing stakeholder

²⁴⁰See California Operational Audit of the California Independent System Operator issued January 25, 2002 in PA02-1-000 and Order Concerning Governance of the California Independent System Operator 100 FERC ¶ 61,059 (2002).

²⁴¹See *Avista Corporation, et al.*, 95 FERC ¶ 61,114 (2001).

²⁴²See *Carolina Power & Light Company*, 94 FERC ¶ 61,273 (2001).

process may not provide adequate representation for all market participants and interested parties. The lack of adequate representation may hinder development of alternative energy resources, such as distributed generation, renewable energy, or demand response programs, since these programs may be contrary to the business interests of certain market participants. Therefore, we are proposing to require that all Independent Transmission Providers satisfy specific governance requirements. Specifically, we are proposing to more clearly define the responsibilities of the Board of Directors, more clearly define the role of stakeholders in selection of the board and in the management of the Independent Transmission Provider, and to establish a process that would be used for selecting the Board of Directors by Independent Transmission Providers.

1. Responsibilities of the Board of Directors

558. As we have previously stated in both Order No. 888 and Order No. 2000, it is critical that the board be independent. The board's primary responsibility is to ensure that the markets operated by the Independent Transmission Provider are operated in a fair, efficient and non-discriminatory manner. The board's focus should be on the interests of the wholesale market, not the interests of particular market participants or classes of market participants. The board should not be regarded as a partner or a contractor of the market participants. Further, the board should be composed of members that are not part of the management of the Independent Transmission Provider. This Commission has the overall responsibility for the function of the wholesale electric market, including setting overall policy for the market. Independent Transmission Providers are public utilities

subject to the Commission's jurisdiction under the Federal Power Act because they own, control or operate jurisdictional transmission facilities and will administer jurisdictional wholesale energy markets. In order to carry out the functions required by Standard Market Design, the board must be fully independent of any market participants. The board is responsible for overseeing the Independent Transmission Provider's administration of the tariff and market rules that have been approved by the Commission. It also must monitor the operation of the markets within its region to identify problems, e.g., the ability to exercise market power, and to propose solutions. In both of these areas, the board is accountable to the Commission, not the market participants and should ensure the following: system reliability and operating efficiency, efficiently functioning markets, and short- and long-term planning objectives. Indeed, the board should ensure that any instance of perceived or real market power or market dysfunction is reported directly and immediately by the MMU to the Commission.

559. An important implication of these principles is that the board must not be a stakeholder board with industry segments given specific seats on the board. The interest of all board members should be a well-functioning market, not representation of a specific industry segment. Similarly, board members must have no financial interests in market participants so that there is no appearance of bias or benefit.

2. Stakeholder Participation

560. Stakeholders have an important role in advising the boards of Independent Transmission Providers. Most current regional organizations have established

stakeholder committees that act either as advisors or in some cases vote on proposals that go before the board.²⁴³ We continue to believe that an active stakeholder process is needed and that to fully satisfy the independence principles of Standard Market Design, these stakeholder committees must be used to advise the Board of Directors rather than function as a decision making body.

561. We are concerned that the current composition of these advisory committees may not adequately represent all segments of the industry. The current structure of many ISO stakeholder committees tends to replicate the functions of vertically integrated utilities. For example, PJM currently has five classes, Generation Owners, Transmission Owners, Other Suppliers, Electric Distributors, and End-Use Customers. Four of these classes represent interests that would benefit from higher levels of demand. Only one represents customers or end-users, and none represents demand-side technologies or alternative load control services such as demand resource management. This sector structure could discourage the introduction of changes that implement new demand management technologies and services, one of the biggest potential outgrowths of the move towards a competitive market. Financial entities, which are usually financial trading firms such as banks or other financial institutions that provide the needed capital to the industry, are

²⁴³In Order No. 2000, we required that these types of stakeholder committees be advisory in RTOs. This meant that the board would have the ability to propose changes to market rules to the Commission whether those changes were approved by the stakeholder committees. We propose to continue this policy for Independent Transmission Providers.

also poorly represented, if at all. Therefore, we propose to require that an Independent Transmission Provider approved by the Commission must have at a minimum committees that reflect six stakeholder classes: (1) generators and marketers, (2) transmission owners (this sector would include vertically integrated utilities), (3) transmission-dependent utilities,²⁴⁴ (4) public interest groups (e.g., consumer advocates, environmental groups, citizen participation), (5) alternative energy providers (e.g., distributed generation, demand response technologies, renewable energy), and (6) end-users and retail energy providers (i.e., load-serving entities that do not own transmission or distribution assets). In addition, we propose to require that there be a separate Regional State Advisory Committee that would advise the board. We believe that six stakeholder classes provides better representation for certain market participants, e.g., transmission-dependent utilities and new technologies that have not been adequately represented in the past. Also, we propose that a company (including all of its affiliates) may have a representative in only one stakeholder sector. For example, a vertically integrated utility that has a marketing affiliate would have to choose whether it would be represented in the transmission owner sector or the generator/marketer sector. This will prevent large corporations from dominating sector representation by placing their affiliates and subsidiaries in several sectors. Initially, the company would be allowed to choose which sector it wished to join. However, requests to change sectors may be subject to limitations to avoid frequent

²⁴⁴These are utilities that must take transmission service from public utilities to provide retail service to their customers.

changes that could be used to affect sector voting results for advisory actions recommended to the board. For example, the corporation may be required to decide which sector it will join on an annual basis. This would allow corporations to change sectors to reflect changes in corporate business models, but not allow frequent changes that could be used to change voting results on particular proposals. We also seek comment on whether or under what circumstances, a stakeholder class should be able to take an issue directly to the board outside the stakeholder process.

3. Initial Selection Process for Board of Directors

562. The initial selection process for the Board of directors must be structured to ensure that board members are independent and have expertise in a variety of transmission and electric market areas. We propose that the following process be used.²⁴⁵

563. First, the qualifications of the board members should be established. We believe it is important that the qualifications be more widely focused than just experience with electric transmission systems. Experience in additional areas such as risk management, generation planning and operation, or technology and innovation would provide the board with a wider background of knowledge in areas crucial to market development. We propose that board candidates be required to have experience in one or more of these fields: senior corporate leadership of a major publicly traded company; professional

²⁴⁵We are not proposing any specific requirements on the number of board members. We anticipate that the board will have between five and nine members, which is consistent with the current size of the Board of Directors for ISOs and proposed for RTOs.

disciplines of finance, accounting, or law; electrical engineering; regulation of utilities; transmission system operation or planning; trading or risk management; information technology; and generation planning or operation. The candidate could have experience in the electric industry in either an Investor-Owned Utility or public power entity. The objective is to have a board that collectively possesses experience in many, if not all, of these areas.

564. Board members or their immediate families should not have current or recent ties (within the last two years) as a director, officer or employee of a market participant in the region or its affiliates. Board members or their immediate families should also not have direct business relationships with market participants or their affiliates. Finally, to the extent that the board member owns stocks or bonds of companies that are market participants, these must be divested within six months of being elected to the board. Prior to divestiture, the board member would not be able to participate in any decisions affecting that market participant or its affiliates. These requirements are necessary to ensure that the board member does not have any financial interest in a market participant that could influence the board member's decision. We propose that board members, their immediate families and senior management be required to fill out annual financial disclosure statements to ensure that there is no conflict of interest. The financial disclosure statements would be available for audit by the Commission.

565. Second, a nationally recognized search firm should be retained by the nominating committee to identify candidates that satisfy these criteria. The search firm should supply

at least two names for each available board seat. The use of a nationally recognized search firm to develop the list of potential board members helps ensure the integrity of the process since the search firm would not have a financial interest in proposing candidates that represent specific market participants or classes of market participants. The search firm should not have a significant ongoing business relationship with the market participants in the region. The search firm must disclose to the nominating committee any ongoing business relationships it has with market participants in the region.

566. A nominating committee composed of two members from each of the stakeholder classes would be formed to review the list of candidates presented by the search firm.

The nominating committee would vote for the individual board candidates as follows.

Each nominating committee member would have the right to cast votes equal to the number of open board seats. A member shall not cast more than one vote for any one candidate and is not required to cast all of its votes.

567. Board seats are filled by a simple majority. Candidates with the highest vote totals are elected to open board seats. Ties for the last open board seats will have a runoff subject to the same rules as the initial selection process. The elected board members would vote to designate one of the members as Chairman of the Board. We seek comment on whether the Chief Executive Officer of the Independent Transmission Provider should be a non-voting member of the board.

568. We recognize that allowing a vote on candidates by stakeholders could be perceived as allowing a sector to dominate the board selection process or result in less

than a fully independent board. While we recognize the concern, we believe that it is important that stakeholders have a voice in the selection process. We do not believe that it is the Commission's role to be the primary decision-maker in determining the candidates that are selected for the board. We seek comment on what protections should be built into the selection process to ensure that a class of market participants does not dominate the stakeholder voting process. Nevertheless, we solicit comment on whether to require the nominating committee to vote on an entire slate of candidates rather than on individual candidates.

4. Succession of Board Members

569. The governance process also needs to include ongoing procedures for the selection of new board members. We believe that the process should seek to maintain a degree of continuity of board membership to ensure stability and consistency in decisionmaking, while at the same time ensuring that the board does change membership over time to allow the introduction of new viewpoints and encourage innovation.

570. To accomplish these two objectives, we propose that the board members have staggered terms. Approximately half of the first board should have initial terms of four years. The remaining board members should have initial terms of three years. All subsequent board members' terms will be for four years. The staggered terms will provide a degree of continuity to the board in its decision making process. We seek comment on whether the proposed staggered terms would lead to too rapid a turnover in the composition of the board. Board members would be permitted to serve no more than

two consecutive terms. This limitation will ensure that there will be a change in board membership over time to allow for the introduction of board members with different experience.

571. The same process that was used to select the initial Board of Directors would be used in the selection process for subsequent board members in the case of resignation, death or removal for cause. Namely a nationally recognized search firm would be retained to identify board candidates. A nominating committee would be formed to review the list of candidates and propose new board members.

572. When the first set of board members terms start expiring a two stage process would be used for electing board members. First, existing board members whose terms are expiring would indicate whether they wished to remain on the board for a second term. The stakeholders would vote on whether these existing board members would remain on the Board of Directors. Second, if there were any remaining vacancies, then a search firm would be retained to provide candidates for the vacant seats on the Board of Directors. The same process that was used for filling the initial Board of Directors would be used for filling these vacancies.

5. Mergers of Independent Transmission Providers

573. We propose the following initial governance structure in the event of a merger of ISOs, RTOs or Independent Transmission Providers. Initially, the board members of the newly formed entity will be comprised of a number of board members from each of the respective organizations in addition to new members. We propose that there should be

equal representation from each former organization plus an equal number of new board members.²⁴⁶ This type of composition will provide the new merged Independent Transmission Provider with the expertise, knowledge and experience during start-up while new board members would bring fresh ideas and perspective. The members from the existing boards will be chosen by their respective boards, after consultation with stakeholders on the expertise and experience needed by the new organization.

574. A nominating committee will nominate all candidates (except the initial members that originate from the original boards of ISOs, RTOs or Independent Transmission Providers) for the initial election of new board members. The initial nominating committee will be composed of two board members from each of the respective merging organizations and the Chairs of two committees representing market operations, reliability and/or management.

M. System Security

575. System security is critical to the reliable operation of the interstate transmission grid. Wholesale electric grid operations are highly interdependent, and a failure of one part of the generation, transmission, or grid management system can compromise the reliable operation of a major portion of the regional grid. The wholesale electric market relies on the continuing reliable operation of not only physical grid resources, but also the operational infrastructure of monitoring, dispatch and market software and systems.

²⁴⁶For example, a nine member board for a merger of two RTOs would reflect 3 members from each of the former RTOs plus three new members.

Because of this mutual vulnerability and interdependence, it is necessary to safeguard the electric grid and market resources and systems by establishing minimum standards for public utilities that own, control or operate facilities used for transmitting electric energy in interstate commerce as well as entities that use these facilities.

576. NERC's Critical Infrastructure Protection Advisory Group has recently developed a set of recommended minimum requirements (standards) for securing information assets that support grid reliability and market operations and the physical environments in which these information assets operate. These standards are designed to ensure that the entity has a basic security program protecting the electric grid and market from the impact of acts, either accidental or malicious, that could cause wide-ranging harmful impacts on grid operations. These standards would be administered through an annual self-certification due January 31, 2004, and every January 31 thereafter. The proposed form for the self-certification is attached as Appendix G.

577. We propose to require that all public utilities that have tariffs on file with the Commission must file the self-certification by January 31, 2004, and every January 31 thereafter. Additionally, on and after February 1, 2004, as a condition of receiving transmission service provided by a public utility that owns, controls or operates transmission facilities, a customer must demonstrate that it has a basic security program in place. The customer can satisfy this requirement by supplying the public utility with a copy of the executed self-certification form. In the case of entities seeking transmission service that are not public utilities subject to the Commission's regulations, the entity

would still be required to demonstrate that it has a basic security program in place to receive transmission services. This could be done by supplying the transmission provider with an executed self-certification using the Commission's form. Alternatively, the transmission provider and the customer could develop an alternative arrangement for ensuring that the customer has a basic security program in place.

578. Finally, when the SMD Tariff is implemented, we propose to extend the requirement to cover the additional services being provided by the Independent Transmission Provider. At that time, any customer seeking to buy or sell through the markets operated by the Independent Transmission Provider or take transmission service under the Network Access Service would be required to demonstrate that it has a basic security program in place.

579. We expect that these standards will be revised and refined over time in light of changes in technology and operational experience with the standards. Therefore, the regulations will also identify the specific version number of the system security standards. When NERC revises the standards, the revisions will be filed with the Commission. The Commission will issue a Notice that it is considering revising the updated system security standards, and we will seek comments on the proposed changes. The process the Commission proposes to use is the same as it has used for standards adopted by the Gas Industry Standards Board for interstate pipelines.²⁴⁷

²⁴⁷Section 284.12(b) of our regulations identifies the business practice and
(continued...)

V. IMPLEMENTATION

580. The Commission proposes to find in the Final Rule that rates, terms and conditions of transmission service and wholesale electric sales that do not comport with the regulations adopted by the Final Rule are unjust, unreasonable or unduly discriminatory. Many of the elements included in Standard Market Design will require computer software development and changes that public utilities may not be able to fully implement for a couple of years. The Commission's objective is to have Standard Market Design implemented on all jurisdictional transmission systems no later than September 30, 2004, or such time as the Commission may establish. The Commission does not believe it is in the public interest to delay implementation of the remedial action to cure undue discrimination or to develop necessary infrastructure until the time when all of the software changes necessary for standard market design are completed. Consequently, the Commission proposes a multi-step process that will be used to bring these rates, terms and conditions of service into conformity with the regulations.

30 Days After Effective Date of Final Rule

581. The Commission will require all public utilities that own, control or operate interstate transmission facilities to begin discussions with stakeholders and state representatives within 30 days after the effective date of the Final Rule about how they

²⁴⁷(...continued)

electronic communication standards promulgated by the Gas Industry Standards Board (now known as NAESB) that interstate pipelines must comply with.

will implement the transition process and comply with the requirements of the Final Rule. These discussions should address selection of an Independent Transmission Provider that will manage the transmission facilities, establishment of a regional state advisory committee, development of a regional transmission planning and expansion program, development of a long-term resource adequacy requirement and identification of areas such as load pockets where mitigation or appropriate infrastructure will be necessary.

July 31, 2003

582. The Commission recognizes that it has accepted many changes to the pro forma tariffs of individual transmission providers that deviate from the pro forma tariff contained in Order No. 888. To the extent these changes involve bundled retail load or give preference to either native load customers or the transmission provider's use of its system, we propose to direct the transmission provider to eliminate them. We have revised the Order No. 888 pro forma tariff to place bundled retail load under the open access transmission tariff, and to eliminate undue preferences for native load customers and the transmission owner's use of its own system.²⁴⁸ The revised Order No. 888 pro forma tariff, which is referred to as the Interim Tariff in this proposed rule, is attached as Appendix A. Pursuant to section 206 of the FPA, we propose to require all public utilities that own, control or operate facilities used for the transmission of electric energy in

²⁴⁸The public utility would make the revisions to its currently effective Open Access Transmission Tariff. The changes to the Order No. 888 tariff are intended to identify the changes that must be made.

interstate commerce to file the Interim Tariff, no later than July 31, 2003. The Interim Tariff will become effective on September 30, 2003, after the peak summer season.

583. Although a transmission tariff rate is already in effect for all public utilities that own, operate or control facilities used for the transmission of electric energy in interstate commerce, we acknowledge that changes to individual utility rates may be necessary as a result of the changes to non-rate terms and conditions that the Interim Tariff requires. Should a public utility determine that such rate changes are warranted by the new non-rate terms and conditions, it may file a new rate proposal pursuant to FPA section 205, no later than July 31, 2003. We will impose a blanket suspension on any such filings that we receive and make them effective, subject to refund, 61 days after they are filed.

584. We also propose a new tariff (SMD Tariff), attached as Appendix B, to supersede the Interim Tariff and implement Standard Market Design. The new SMD Tariff includes many areas in which the Independent Transmission Provider would propose provisions consistent with the policy framework set forth in the Final Rule, but designed to meet the specific circumstances of the region. We propose to give regions discretion in developing a transition program for existing contracts that is consistent with the guidelines set forth in the Final Rule.

585. The Commission recognizes that public utilities will need time to ensure that transmission facilities are operated by an Independent Transmission Provider, implement Network Access Service, establish day-ahead and real-time markets, adopt LMP for congestion management, incorporate market power mitigation measures customized for

the region, develop a market monitoring program and develop a resource adequacy requirement for the region. Thus, for these requirements the Commission proposes a process for implementation that provides an opportunity for active participation by state representatives and market participants and that gives the Commission opportunities to review progress and require changes if sufficient progress is not being made.

586. To implement the requirements of Standard Market Design, we propose to require every public utility that owns, controls or operates facilities used for the transmission of electric energy in interstate commerce to select an Independent Transmission Provider to operate its transmission facilities. A public utility may meet this requirement by: (1) itself satisfying the definition of Independent Transmission Provider; (2) turning over its transmission facilities to a Commission-approved RTO that meets the definition of Independent Transmission Provider; or (3) contracting with an entity that meets the definition of Independent Transmission Provider to operate its transmission facilities.

587. The Commission will require all public utilities that own, operate or control interstate transmission facilities to file an Implementation Plan for compliance with the regulations no later than July 31, 2003. In the Implementation Plan, the public utility must identify the independent entity that will serve as the Independent Transmission Provider for the transmission facilities that the public utility owns, controls or operates. (A public utility that is already a member of an entity that satisfies the definition of Independent Transmission Provider may request a waiver from this requirement in its Implementation Plan filing.) Additionally, the Implementation Plan must include time

lines and a proposal for compliance with the long-term resource adequacy requirements of the Final Rule. Further, the Implementation Plan must identify the software vendor(s) that the public utility will use for implementation of Standard Market Design and a time line that identifies implementation milestones and indicates the projected timing of their completion. The Commission wants to ensure that the cost of implementation of Standard Market Design is reasonable, and intends to closely monitor the expenditures incurred to implement the Final Rule. Therefore, we propose to require that all public utilities include in their Implementation Plan a detailed estimate of their projected cost of implementing the Final Rule. The estimate should include projected software costs as well as other costs that the public utility may incur. The public utility will also be required to file status reports on the Implementation Plan on a quarterly basis. The Commission will review the Implementation Plans and quarterly reports to ensure compliance with the regulations. Also, the Commission will establish appropriate procedures, if needed, for resolving concerns of state representatives and market participants.

588. The Commission recognizes that some public utilities will be able to implement Standard Market Design more quickly than others. The dates proposed in the Implementation Plan should reflect the level of changes that are required. The Commission intends to be flexible in setting compliance dates for Standard Market Design. The Commission expects that those public utilities that do not require significant changes could implement Standard Market Design much sooner than others. While the

Commission's objective is to have Standard Market Design in place everywhere by September 30, 2004,, it will consider requests to extend this date if the public utility can document that additional time is necessary.

589. Finally, the public utility must cooperate with others in its region to have a Regional State Advisory Committee in place by July 31, 2003.

Six Months After Effective Date of Final Rule

590. The Commission proposes to require all public utilities that own, control or operate facilities used for the transmission of electric energy in interstate commerce to begin a regional transmission planning process within six months and produce a plan within one year of the effective date of the Final Rule. This will be an intermediate step in the process of satisfying the planning and expansion requirements contained in section 35.34(k)(7) of the Commission's regulations.²⁴⁹ The Independent Transmission Provider will take over this process when it becomes operational.

December 1, 2003 and September 30, 2004

591. Pursuant to section 206 of the FPA, by December 1, 2003 all Independent Transmission Providers will be required to file the SMD Tariff, including language that explains the Independent Transmission Provider's proposals for market monitoring, market power mitigation, long-term resource adequacy, transmission planning and expansion, transmission pricing and any changes to the SMD Tariff necessary to

²⁴⁹18 C.F.R § 35.34(k)(7) (2002).

accommodate regional needs. The filing must also indicate the date, which must be no later than September 30, 2004, or such date as the Commission may establish, when the Independent Transmission Provider will be able to fully implement Standard Market Design. The Commission must approve the tariff filing before the Independent Transmission Provider will be able to implement Standard Market Design. We anticipate acting on these filings on a timely basis so that the Independent Transmission Providers will know several months before the planned implementation date any changes that are required in these filings.

592. As a result of the changes required by the Final Rule, the Independent Transmission Provider or transmission owners may believe that other changes are needed in their transmission rates for jurisdictional service. Transmission owners and Independent Transmission Providers should file these types of changes under section 205 of the FPA at least 60 days prior to the date on which they propose to implement Standard Market Design. The Commission intends the implementation process to be a collaborative one. The Commission directs public utilities to meet with stakeholders and state commissions on a regular basis to discuss the changes that are necessary to comply with the Final Rule. Based on the filings that are received, the Commission may also establish technical conferences, mediation efforts or other procedures as necessary to ensure that all public utilities that own, control or operate interstate transmission facilities will be operating under Standard Market Design no later than September 30, 2004, or such time as the Commission may establish.

593. Further, the Commission intends this phased compliance process to encourage joint compliance filings. Public utilities may submit a single, joint application to meet the requirements of Standard Market Design, and Independent Transmission Providers may make necessary filings on behalf of their public utility members. Such joint filings may streamline the compliance process and reduce its costs.

January 31, 2004

594. The Commission proposes to require all public utilities to provide assurances to the Independent Transmission Provider with which they are affiliated that the public utilities comply with minimum security standards. We propose to require public utilities that have transmission tariffs on file with the Commission to file the self-certification of compliance with security standards that is attached as Appendix G. The self-certification must be submitted by January 31, 2004, and every January 31 thereafter. On and after February 1, 2004, any transmission customer (including a non-jurisdictional entity) that seeks to receive transmission service from a public utility that owns, controls or operates facilities used for the transmission of electric energy in interstate commerce must provide assurances to the transmission provider that it has a basic security system in place. This may be done by providing the transmission provider with a copy of the executed self-certification form, or the transmission provider and customer may make alternate arrangements. Following the implementation of Standard Market Design, we propose to extend this self-certification requirement to apply to any customer seeking to buy or sell through the Independent Transmission Provider's markets or take Network Access

Service.

VI. PUBLIC COMMENT PROCEDURES

595. The Commission invites interested persons to submit comments, data, views and other information concerning matters set out in this proposed rule. To facilitate the Commission's review of the comments, the Commission requests commenters to provide an executive summary (not to exceed ten pages) of their positions. To the greatest degree possible, commenters should use the topic headings that the proposed rule uses and arrange their comments in the order of topics presented in this proposed rule, and cite the specific referenced paragraph numbers. Commenters should identify separately any additional issues that they may wish to address. Commenters should double-space their comments. Comments must refer to Docket No. RM01-12-000, and may be filed on paper or electronically via the Internet. The Commission must receive all comments no later than 75 days after the issuance of this notice of proposed rulemaking. Comments should include an executive summary that should not exceed ten pages. Those filing electronically do not need to make a paper filing. Reply comments will not be entertained.

596. Those making paper filings should submit the original and 14 copies of their comments to the Office of the Secretary, Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426.

597. The Commission strongly encourages electronic filings. Commenters filing their comments via the Internet must prepare their comments in WordPerfect, MS Word,

Portable Document Format, or ASCII format (see <http://www.ferc.gov/documents/electronicfilinginitiative/efi/efi.htm>, in particular "User Guide"). To file the document, access the Commission's website at www.ferc.gov and click on "e-Filing" and then follow the instructions for each screen. First time users will have to establish a user name and password. The Commission will send an automatic acknowledgment to the sender's E-Mail address upon receipt of comments. User assistance for electronic filing is available at 202-208-0258 or by E-Mail to efiling@ferc.gov. Do not submit comments to the E-Mail address.

598. The Commission will place all comments in the Commission's public files and they will be available for inspection in the Commission's Public Reference Room at 888 First Street, N.E., Washington D.C. 20426, during regular business hours. Additionally, all comments may be viewed, printed, or downloaded remotely via the Internet through FERC's Homepage using the FERRIS link.

VII. REGULATORY FLEXIBILITY ACT

599. The Regulatory Flexibility Act²⁵⁰ requires rulemakings to contain either a description and analysis of the effect that the proposed rule will have on small entities or a certification that the rule will not have a significant economic impact on a substantial number of small entities.

600. This rule applies to public utilities that own, control or operate interstate

²⁵⁰ 5 U.S.C. 601-612 (1994).

transmission facilities, not to electric utilities per se. The total number of public utilities that, absent waiver, would have to modify their current open access transmission tariffs by filing the Interim Tariff is 176.²⁵¹ Of these only 6 public utilities, or less than two percent, dispose of 4 million MWh or less per year.²⁵² We do not consider this a substantial number, and in any event, these small entities may seek waiver of the Standard Market Design Final Rule requirements.²⁵³

601. With respect to the Interim Tariff, the Commission will specify precisely the terms and conditions that public utilities will have to incorporate into their existing tariffs, and this will considerably reduce the burden of modifying transmission tariffs. In order to implement the SMD Tariff, every public utility that owns, controls or operates facilities used for the transmission of electric energy in interstate commerce must (a) meet the definition of Independent Transmission Provider, (b) turn over the operation of its

²⁵¹The sources for this figure are FERC Form No. 1 and FERC Form No. 1-F data.

²⁵²Id.

²⁵³The Regulatory Flexibility Act defines a "small entity" as "one which is independently owned and operated and which is not dominant in its field of operation." See 5 U.S.C. 601(3) and 601(6)(1994); 15 U.S.C. 632(a)(1) (1994). In Mid-Tex Elec. Coop. v. FERC, 773 F.2d 327, 340-343 (D.C. Cir. 1985), the court accepted the Commission's conclusion that, since virtually all of the public utilities that it regulates do not fall within the meaning of the term "small entities" as defined in the Regulatory Flexibility Act, the Commission did not need to prepare a regulatory flexibility analysis in connection with its proposed rule governing the allocation of costs for construction work in progress (CWIP). The CWIP rules applied to all public utilities. The Standard Market Design rules will apply only to those public utilities that own, control or operate interstate transmission facilities. These entities are a subset of the group of public utilities found not to require preparation of a regulatory flexibility analysis for the CWIP rule.

transmission facilities to a regional transmission organization that meets the definition of Independent Transmission Provider, or ©) contract with an entity that meets the definition of Independent Transmission Provider to operate its transmission facilities. We do not expect that any entity that must file an SMD Tariff would be a small entity as defined by the Regulatory Flexibility Act.

602. We do not, therefore, believe that the requirement of filing the Interim Tariff and SMD Tariff will impose a significant economic impact on small entities. Consequently, the Commission certifies that this proposed rule will not have a significant economic impact upon a substantial number of small entities.

VIII. ENVIRONMENTAL STATEMENT

603. In furtherance of the National Environmental Policy Act of 1969, the Commission will prepare an environmental assessment (EA) that will consider the environmental impacts of the proposed rule. A notice of intent to prepare the EA, including a request for comments on the scope of the EA and notice of a public scoping meeting was issued on July 26, 2002.²⁵⁴

IX. PUBLIC REPORTING BURDEN AND INFORMATION COLLECTION STATEMENT

604. The Commission is submitting the following collections of information contained in this proposed rule to the Office of Management and Budget (OMB) for review under

²⁵⁴Notice on Intent to Prepare an Environmental Assessment and Request for Comments on the Scope of Issues to be Addressed for the Proposed Rulemaking on Electricity Market Design and Structure, Docket No. RM01-12-000 (July 26, 2002).

Section 3507(d) of the Paperwork Reduction Act of 1995. The Commission identifies the information provided under Part 35 as FERC-516.

605. The Commission solicits comments on the Commission's need for this information, whether the information will have practical utility, the accuracy of the provided burden estimates, ways to enhance the quality, utility and clarity of the information that the Commission will collect, and any suggested methods for minimizing respondent's burden, including the use of automated information techniques. The burden estimates for complying with this proposed rule are as follows:

Data Collection	Number of Respondents	Number of Responses	Hours Per Response	Total Annual Hours
FERC-516	176	1	1,229*	216,304
	176	4	3	2,112
	12	1	92	1,104
Totals			1,324	219,520

*rounded off.

Respondent	Document	Recipient	Required Content	Hours Per Response
All public utilities that own operate or control transmission facilities	(no document required)	Stakeholders and state representatives	Public utilities must discuss with stakeholders and state representatives how they will implement the transition process and comply with the Final Rule: 1. Selection of Independent Transmission Provider. 2. Establishment regional state advisory committee. 3. Development of regional transmission planning /expansion program. 4. Development of a long-term resource adequacy requirement. 5. Identification of areas where mitigation or appropriate infrastructure will be needed.	430 hours
All public utilities that own, operate or control transmission facilities	Revisions to Order No. 888 tariff (Interim Tariff) or request for waiver of this requirement	FERC	Tariff language to place service to bundled retail customers under OATT, eliminate preferences for native load and for a transmission provider's own use of its system.	182 hours

All public utilities that own, operate or control transmission facilities	Implementation plan for compliance with proposed regulations	FERC	<ol style="list-style-type: none"> 1. Identify Independent Transmission Provider (or request waiver of this requirement). 2. Time line and proposal for compliance with long term resource adequacy requirements. 3. Identify software vendor(s) to be used for implementation of Standard Market Design. 4. Implementation time line showing projected timing and completion of milestones for software development. 5. Detailed estimate of costs of implementing Standard Market Design. 	193 hours
Public utilities	Quarterly Reports	FERC	Implementation Plan Status	3 hours
Transmission Provider	Proposed tariff language	FERC	<ol style="list-style-type: none"> 1. SMD Tariff, including proposed language for market monitoring and market power mitigation; long-term resource adequacy; transmission planning and expansion; changes to SMD Tariff needed to accommodate regional needs. 2. Date by which transmission provider will fully implement Standard Market Design. 	124 hours
Transmission Provider	Section 205 filing requesting approval of adjustment of revenue requirement (optional)	FERC	Section 205 filing demonstrating that transmission provider's revenue requirement should be adjusted to recover additional costs associated with conversion pre-Order No. 888 contracts to service under new tariff and allocation of congestion revenue rights directly to customers.	*If respondent decides to submit a §205 filing, the burden is already covered under existing requirements

Transmission Provider/participating generators	Participant Generator agreements	FERC	1. Identify noncompetitive conditions in which generator would have to self-schedule or supply all capacity to spot markets. 2. Specify bid caps that would apply to generator's day-ahead and real-time bids.	34 hours
Transmission Provider	Reliability proposals	FERC	Proposal regarding implications of each reliability procedure (e.g. curtailment) for market prices in energy and ancillary services markets	63 hours
Transmission Provider	Transmission Expansion Plan	FERC	Have in place a regional transmission planning process and complete first transmission expansion plan pursuant to 18 C.F.R. § 35.34(k)(7).	120 hours
Market Monitoring Unit	Initial competitive market analysis	FERC	1. Identify load pockets that require different bid mitigation triggers. 2. Identify generators that may be required for reliability.	78 hours
Market Monitoring Unit	Annual update of Initial competitive market analysis	FERC	Report current status on load pockets and generators for reliability	14 hours
Load serving entities	Resource adequacy report	RTO	Report and document plan to either meet share of regional adequacy requirement or curtail if necessary	38 hours
Load serving entities	Plan for curtailment during regional power shortage, if load-serving entity does not/will not meet its share of RTO's long-term regional adequacy requirement	RTO	1. Identify customers to be curtailed first in event of regional power shortage. 2. Acknowledge willingness to be among first curtailed.	42 hours
RTOs	Regional Demand Forecast	RTO	Regional demand forecast for its region for the planning horizon	To be determined

All public utilities with a transmission tariff on file with the Commission	Self-certification of compliance with system security standards	FERC	Completed and executed form contained in Appendix G to Notice of Proposed Rulemaking	2 hours
All public utilities with a transmission tariff on file with the Commission	Annual recertification of compliance with system security standards	FERC	Completed and executed form contained in Appendix G to Notice of Proposed Rulemaking	.5 hours

Total Annual Hours for Collection (reporting + record keeping (if appropriate)) =

219,520 hours.

Information Collection Costs:

606. Because of the regional differences and the various staffing levels that will be involved in preparing the documentation (legal, technical and support), the Commission is using an hourly rate of \$50 to estimate the costs for filing and other administrative processes (reviewing instructions, adjusting existing ways to comply with previously applicable instructions or requirements, training personnel to be able to respond to the information collection, searching data sources, completing and transmitting the collection of information and conducting outreach sessions with all affected entities) associated with this proposed rule. The estimated cost is anticipated to be \$10,976,000 (219,520 hours x \$50) for this portion of the rule.

607. In addition, there is a separate component that must also be considered when implementing the requirements of this proposed rule, the costs for information technology (IT) needed to implement the SMD Tariff. The number of entities to be impacted at this

phase of the rule's implementation will be fewer than at the Interim Tariff stage, but is still unknown at this time. Further, several entities are already developing or employing software that may be sufficient to implement the SMD Tariff, and the entities' software packages are at different stages of development. There are also regional differences to consider (as noted above) with respect to labor compensation. For these reasons, the Commission seeks comments on the anticipated costs for IT development associated with this proposed rule. When preparing their estimates, commenters should take into consideration design, procurement and operation costs for the following: (1) data collection systems (including monitors, detection systems, control systems and other equipment necessary to obtain information or data of interest, as well the facilities and equipment necessary to house and operate such systems); (2) data management systems necessitated by the data collection(s) (including computers and other hardware, programs and other software, storage media and facilities); and (3) data reporting systems necessitated by the information collection (including electronic links, installing and operating the reporting components of an information management system and the burden of maximizing public accessibility). These investments in information technology are for systems whose useful lifetime exceeds the expiration of the data collection (which must be reviewed and approved by OMB after three years), so the costs for this reporting burden needs to be estimated based on the costs of a longer-lived investment. OMB regulations require OMB to approve certain information collection requirements imposed

by agency rule.²⁵⁵ Accordingly, pursuant to OMB regulations, the Commission is providing notice of its proposed information collections to OMB.

Title: FERC-516, Electric Rate Schedule Filings

Action: Proposed Data Collections.

OMB Control No.: 1902-0096

The applicant shall not be penalized for failure to respond to this collection of information unless the collection of information displays a valid OMB control number.

Respondents: Business or other for profit.

Frequency of Responses: One time.

Necessity of Information: The proposed rule would revise the requirements contained in 18 C.F.R. part 35. The Commission is seeking to standardize wholesale electric market design and transmission service. The Commission proposes to develop a standardized set of electricity market rules that reflects many of the recommendations and suggestions elicited from all market participants.

608. The proposed Standard Market Design rules are intended to have a generally positive impact on these market participants. For example, the proposed Standard Market Design rules will facilitate direct dealings between market participants who want to secure long-term bilateral power supply arrangements. The proposed Standard Market Design rules will also facilitate short-term transactions that are made in the spot market to

²⁵⁵See 5 C.F.R. § 1320.11 (2002).

make up for imbalances (differences) between scheduled electricity supplies that were matched to projected load levels, and the load levels that actually develop. Through these proposed Standard Market Design rules, sellers will be able to more effectively sell into the market and buyers will be able to more efficiently buy from the market because they will not need to be directly matched up at the last minute on a real-time hourly and day-ahead basis. In addition, the proposed Standard Market Design rules will bolster customers' ability to profitably participate in programs designed to encourage reductions in loads to offset electricity supply shortages. Finally, the proposed Standard Market Design rules will foster the trading of Congestion Revenue Rights among transmission customers that will allow them to protect against congestion charges.

609. Up to 176 public utilities that own, operate or control transmission would be required to implement the Commission's Standard Market Design Rule. The revised open access transmission component of the Standard Market Design Rule would be incorporated as an interim amendment to the existing transmission tariffs of all jurisdictional transmission providers operating in interstate commerce. Independent Transmission Providers would also be required to file SMD Tariffs contained in the Final Rule to implement Network Access Service and Standard Market Design. To the extent an affected public utility participates in an RTO, or contracts with an Independent Transmission Provider, the RTO or Independent Transmission Provider will be permitted to make the required filing on behalf of the affected public utility. Public utilities also will be permitted to file Implementation Plans jointly with other utilities. Further, the

Commission proposes to entertain requests for waivers of the requirement to make compliance filings. These features of the proposed rule would lessen the incidence of Standard Market Design compliance filings. We have estimated for purposes of this analysis that RTOs and ITPs may number from 5 to 12 entities in the lower 48 states.

Internal Review: The Commission has assured itself, by means of internal review, that there is specific, objective support for the burden estimates associated with the information requirements. The Commission's Office of Markets, Tariffs and Rates will use the data included in filings under Sections 203 and 205 of the Federal Power Act to evaluate efforts for the interconnection and coordination of the United States electric transmission system and to ensure the orderly formation and operation of a standard design in wholesale electric transmission markets, as well as for general industry oversight. These information requirements conform to the Commission's plan for efficient information collection, communication, and management within the electric power industry.

610. Interested persons may obtain information on the reporting requirements by contacting the following: Federal Energy Regulatory Commission, 888 First Street, N.E., Washington D.C. 20426 [Attention Michael Miller, Capital Planning and Policy Group, Phone: (202) 208-1415, fax: (202) 208-2425, E-Mail: michael.miller@ferc.gov.]

611. Please send your comments concerning the collection of information(s) and the associated burden estimates to the contact listed above and to the Office of Management and Budget, Office of Information and Regulatory Affairs, Washington, D.C. 20503

[Attention: Desk Officer for the Federal Energy Regulatory Commission, phone: (202) 395-3087, fax: (202) 395-7285].

X. DOCUMENT AVAILABILITY

612. In addition to publishing the full text of this document in the Federal Register, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the Internet through FERC's Home Page (<http://www.ferc.gov>) and in FERC's Public Reference Room during normal business hours (8:30 a.m., to 5:00 p.m. Eastern time) at 888 First Street, N.E., Room 2A, Washington, DC 20426.

613. From FERC's Home Page on the Internet, this information is available in the Federal Energy Regulatory Records Information System (FERRIS). The full text of this document is available on FERRIS in PDF and WordPerfect format for viewing, printing, and/or downloading. To access this document in FERRIS, type the docket number of this document, excluding the last three digits in the docket number field. User assistance is available for FERRIS and the FERC's Website during normal business hours from our Help Line at (202) 208-2222 (E-Mail to WebMaster@ferc.gov) or the Public Reference at (202) 208-1371 Press 0, TTY (202) 208-1659 (E-Mail to public.reference.room@ferc.gov).

614. List of subjects in 18 CFR Part 35

Electric power rates, Electric utilities, Electricity, Reporting and recordkeeping requirements.

By direction of the Commission. Commissioner Breathitt concurred with a separate statement attached.

(S E A L)

Magalie R. Salas,
Secretary.

In consideration of the foregoing, the Commission proposes to amend Part 35, Chapter I, Title 18, Code of Federal Regulations, as follows.

REGULATORY TEXT

PART 35 – FILING OF RATE SCHEDULES

1. The authority citation for Part 35 continues to read as follows:

Authority: 16 U.S.C. § 791a-825r, 2601-2645; 31 U.S.C. § 9701; 42 U.S.C. § 7101-7352.

2. Part 35 is amended by adding a new Subpart G, Procedures and Requirements Regarding Non-Discriminatory Open Access Transmission Services and Standard Market Design, including new §§ 35.35, 35.36, 35.37 and 35.38 to read as follows:

§ 35.35 Standard Market Design Tariff

(a) Applicability. This section applies to any public utility that owns, controls or operates facilities used for the transmission of electric energy in interstate commerce and to any Independent Transmission Provider.

(b) Definitions--

(1) Independent Transmission Provider. As used herein the term Independent Transmission Provider shall mean any public utility that owns, controls or operates facilities used for the transmission of electric energy in interstate commerce, that administers the day-ahead and real-time energy and ancillary services markets in connection with its provision of transmission services pursuant to the pro forma tariff

contained in Order No. __, FERC Stats. & Regs. ¶ ____ (Final Rule on Electricity Market Design and Structure), and that is independent (i.e., has no financial interest, either directly or through an affiliate, as defined in section 2(a)(11) of the Public Utility Holding Company Act (15 U.S.C. § 79b(a)(11)), in any market participant in the region in which it provides transmission services or in neighboring regions).

(2) Market Participant. As used herein the term Market Participant shall mean:

(i) any entity that, either directly or through an affiliate, sells or brokers electric energy, or provides ancillary services to the Independent Transmission Provider, unless the Commission finds that the entity does not have economic or commercial interests that would be significantly affected by the Independent Transmission Provider's actions or decisions; and

(ii) any other entity that the Commission finds has economic or commercial interests that would be significantly affected by the Independent Transmission Provider's actions or decisions.

(c) Non-discriminatory open access transmission services and standard market design.

(1) Every public utility that owns, controls or operates facilities used for the transmission of electric energy in interstate commerce, shall provide non-discriminatory open access services through the interim tariff contained in Order No. __, FERC Stats. & Regs. ¶ ____ (Final Rule on Electricity Market Design and Structure) no later than

September 30, 2003. Such tariff shall remain on file with the Commission until it is superseded by the pro forma tariff contained in Order No. ___, FERC Stats. & Regs. ¶ ____ (Final Rule on Electricity Market Design and Structure).

(2) To implement the requirements of Non-Discriminatory Open Access Transmission Services and Standard Market Design, every public utility that owns, controls or operates facilities used for the transmission of electric energy in interstate commerce must (a) meet the definition of Independent Transmission Provider, (b) turn over the operation of its transmission facilities to a regional transmission organization, as defined in section 35.34(b)(1) of this title, that meets the definition of Independent Transmission Provider, or (c) contract with an entity that meets the definition of Independent Transmission Provider to operate its transmission facilities.

(i) Every public utility that owns, controls or operates facilities used for the transmission of electric energy in interstate commerce as of [effective date of Standard Market Design Rule] must comply with this requirement by September 30, 2004, or such other date as determined by the Commission. Such public utility must inform the Commission which Independent Transmission Provider will operate the public utility's transmission facilities, and provide further information about its plans to implement Standard Market Design as specified in Order No. ___, FERC Stats. & Regs. ¶ ___, no later than July 31, 2003. Every public utility that owns, controls or operates facilities used for the transmission of electric energy in interstate commerce after the effective date of this rule must comply no later than 60 days prior to the time its facilities

are used for transmission in interstate commerce.

(ii) A public utility that is a member of an approved regional transmission organization or an independent system operator or other entity that meets the definition of Independent Transmission Provider may file a request for a waiver of the filing requirements of this paragraph on the ground that it has already complied with the requirement. An application for a waiver must be filed no later than July 31, 2003, or no later than 60 days prior to the time the public utility's transmission facilities are used for transmission in interstate commerce.

(3) Pursuant to section 206 of the Federal Power Act, any entity that meets the definition of Independent Transmission Provider must file with the Commission a tariff of general applicability for the provision of transmission services, including ancillary services and the administration of the day-ahead and real-time energy and ancillary services markets. Such tariff must be the pro forma tariff contained in Order No. __, FERC Stats. & Regs. ¶ ____ (Final Rule on Electricity Market Design and Structure) or such other open access tariff as may be approved by the Commission consistent with Order No. __, FERC Stats. & Regs. ¶ ____ (Final Rule on Electricity Market Design and Structure). Such tariff must include proposed language that explains the Independent Transmission Provider's proposals for market monitoring, market power mitigation, long-term resource adequacy, transmission planning and expansion, transmission pricing, changes to the pro forma tariff necessary to accommodate regional needs, and further information as specified in the pro forma tariff contained in Order No. __

___, FERC Stats. & Regs. ¶ ___ (Final Rule on Electricity Market Design and Structure).

The filing also shall specify the date on which the Independent Transmission Provider proposes to implement Standard Market Design.

(4) The Independent Transmission Provider shall file, pursuant to section 205 of the Federal Power Act, any changes to its transmission rates necessary to implement Standard Market Design, no later than 60 days prior to the date on which it proposes to implement Standard Market Design, or 60 days prior to the time its facilities are used for transmission in interstate commerce.

(5) One or more public utilities may jointly file an application to meet the requirements of this paragraph.

(6) An Independent Transmission Provider may make necessary filings on behalf of public utilities required to meet the requirements of this paragraph.

(7) The interim tariff and pro forma tariff contained in Order No. ___, FERC Stats. & Regs. ¶ ____ (Final Rule on Electricity Market Design and Structure) will not apply to transmission of electric energy pursuant to contracts that were executed on or before July 9, 1996 and remain in effect as of [effective date of Standard Market Design Rule]. Customers under such contracts may elect to convert their contracts, consistent with their contract terms, to service under the pro forma tariff contained in Order No. ___, FERC Stats. & Regs. ¶ ___ (Final Rule on Electricity Market Design and Structure) at any time after [effective date of Standard Market Design Rule].

(8) Waivers. A public utility subject to the requirements of this section may

file a request for waiver of all or part of the requirements of this section, for good cause shown. An application for waiver must be filed no later than [effective date of Standard Market Design Rule], or no later than 60 days prior to the time the Independent Transmission Provider would otherwise have to comply with the requirement.

(d) Non-public utility procedures for tariff reciprocity compliance.

(1) A non-public utility may submit a transmission tariff and a request for declaratory order that its voluntary transmission tariff provides transmission service that is comparable to the service that the non-public utility provides itself.

(i) Any submittal and request for declaratory order submitted by a non-public utility will be provided an NJ (non-jurisdictional) docket designation.

(ii) If the submittal is found to be an acceptable transmission tariff, an applicant in a Federal Power Act (FPA) section 211 case against the non-public utility shall have the burden of proof to show why service under the open access tariff is not sufficient and why a section 211 order should be granted.

(2) A non-public utility may file a request for waiver of all or part of the reciprocity conditions contained in a public utility open access tariff, for good cause shown. An application for waiver may be filed at any time.

(3) If a non-public utility has on file with the Commission, as of [effective date of Standard Market Design Rule], a reciprocity tariff accepted by the Commission, the non-public utility is not required to make a filing under paragraph (d) of this section.

§ 35.36 Market monitoring and market power mitigation.

(a) The Independent Transmission Provider must have a market monitoring unit that is independent of the Independent Transmission Provider's management and that is accountable to the Commission. The market monitoring unit will provide information and recommendations to the Commission and the governing board of the Independent Transmission Provider.

(b) The market monitoring unit will monitor all markets run by the Independent Transmission Provider and the operation of the transmission grid for exercises of market power, flaws in the Independent Transmission Provider's tariff rules or operations that contribute to economic inefficiency, and market participants' compliance with the Independent Transmission Provider's tariff. The market monitoring unit also shall perform further duties as instructed by the Commission.

(c) The market monitoring unit will report at least annually on the structure and performance of the markets in the Independent Transmission Provider's region. The report must include, at a minimum: (i) a description of market operations, supply and demand, and market prices, (ii) an structural analysis of the market, including an evaluation of barriers to entry, (iii) an assessment of market performance, including an assessment of market participant behavior, (iv) an evaluation of the effectiveness of the existing market power mitigation, and (v) recommendations for improving the market design or market power mitigation measures to improve the efficiency of the market. The market monitoring unit also shall provider further reports as directed by the Commission.

(d) The Independent Transmission Provider must include in its tariff provisions requiring market participants, as a condition of participating in the markets operated by the Independent Transmission Provider and using the interstate transmission facilities operated by the Independent Transmission Provider,

(i) to agree to provide to the market monitoring unit all information and data requested by the market monitoring unit to perform its functions under these rules and the Independent Transmission Provider's tariff, and

(ii) to agree to penalties specified in the Independent Transmission Provider's tariff for the violation of any tariff provisions.

(e) The market monitoring unit is responsible for administering the market power mitigation provisions of the Independent Transmission Provider's tariff.

§ 35.37 Long-term electric energy resource adequacy.

(a) Each Independent Transmission Provider must ensure that the level of planned regional resources for a future year (the last year of the planning horizon) is adequate.

Annually, each Independent Transmission Provider must:

(i) perform an electric energy demand forecast for the last year of the planning horizon;

(ii) apportion the regional resource adequacy requirement for the last year of the planning horizon among the load serving entities in its area on the basis of the ratio of their loads;

(iii) require each load-serving entity in its area to submit to the Independent Transmission Provider a plan (including generation, transmission and demand-side options) to meet the load-serving entity's share of the regional resource adequacy requirement for the last year of the planning horizon; and

(iv) ensure that each load-serving entity's electric energy resource plan meets standards approved by the Commission and is feasible, including ensuring that resources are not double counted by different load serving entities.

(b) This requirement shall replace installed capacity requirements approved by the Commission prior to [effective date of Standard Market Design Rule].

§ 35.38 Long-term transmission planning and expansion.

(a) Each Independent Transmission Provider shall keep on file with the Commission a regional transmission expansion plan.

(b) Each Independent Transmission Provider's regional transmission expansion plan shall, at a minimum:

(1) permit all market participants to participate equally in a facilitated process to identify transmission projects that would best serve the needs of the region; and

(2) require the Independent Transmission Provider to issue requests for proposals to address transmission planning needs identified through such a process.

(c) Independent Transmission Providers shall satisfy the provisions of section 35.34(k)(7) of this title no later than the date on which service commences under Standard Market Design.